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ENERGY CONVERSION ALTERNATIVES STUDY (ECAS) SUMMARY REPORT

Prepared by

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

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Cleveland, Ohio 44135

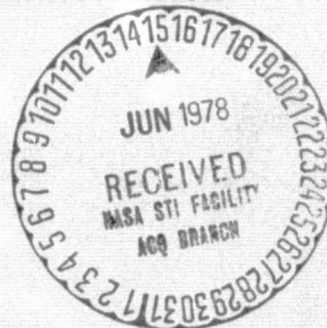
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16. Abstract ECAS compared various advanced energy conversion systems that can use coal or coal-derived fuels for baseload electric power generation. The study was sponsored by the Energy Research and Development Administration, the National Science Foundation, and the National Aeronautics and Space Administration. It was conducted in two phases. Phase 1 consisted of parametric studies performed by the General Electric Co. and the Westinghouse Electric Corp. From these results, 11 concepts were selected for further study in Phase 2. The Phase 2 conceptual designs were prepared by the General Electric Co., the Westinghouse Electric Corp., and the United Technologies Corp./Burns and Roe, Inc. For each of the Phase 2 systems and a common set of ground rules, performance, cost, environmental intrusion, and natural resource requirements were estimated. In addition, the contractors defined the state of the associated technology, identified the advances required, prepared preliminary research and development plans, and assessed other factors that would affect the implementation of each type of powerplant. The systems studied in Phase 2 include steam systems with atmospheric- and pressurized-fluidized-bed boilers; combined-cycle gas turbine/steam systems with integrated gasifiers or fired by a semiclean, coal-derived fuel; a potassium/steam system with a pressurized-fluidized-bed boiler; a closed-cycle gas turbine/organic system with a high-temperature, atmospheric-fluidized-bed furnace; a direct-coal-fired, open-cycle magnetohydrodynamic/steam system; and a molten-carbonate fuel cell/steam system with an integrated gasifier. During each phase, NASA analyzed the contractors' results to reconcile differences and to compare the systems. The sensitivity of the results to changes in the ground rules and the impact of uncertainties in capital cost estimates were also examined. This report is a summary of the NASA reports dealing with both phases of ECAS.					
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ENERGY CONVERSION ALTERNATIVES STUDY

(ECAS) - SUMMARY REPORT

Lewis Research Center

1.0 SUMMARY

The Energy Conversion Alternatives Study (ECAS) was conducted by the Lewis Research Center under the sponsorship of the Energy Research and Development Administration (ERDA), the National Science Foundation (NSF), and the National Aeronautics and Space Administration (NASA). Overall guidance for the study was provided by an Interagency Steering Committee consisting of members of each participating agency. Two advisory panels assisted the Interagency Steering Committee - a Technical Advisory Panel and a Utility Advisory Panel.

The overall objectives of this study were to investigate advanced energy conversion techniques for baseload electric utility applications that can use coal or coal-derived fuels and to evaluate their relative merits and potential benefits according to a common set of ground rules. Estimates were made of performance, cost, environmental intrusion, and natural resource requirements for these systems. In addition, the ECAS contractors defined the state of the associated technology, identified the technological advances required, and prepared preliminary research and development plans for selected advanced system concepts.

The study was conducted in two phases. Phase 1 consisted of parametric analysis, and Phase 2 treated conceptual design of certain selected powerplants together with development plans and an implementation assessment. In Phase 1, emphasis was placed on broad coverage of the energy conversion systems over wide ranges of parametric conditions. Approximately 900 parametric points were calculated by two contractor teams led by the General Electric Co. and the Westinghouse Electric Corp. The results were compared and evaluated at the NASA Lewis Research Center. Systems studied in Phase 1 included steam plants with advanced furnaces, open-cycle recuperated gas turbines, combined-cycle gas turbine/steam systems, helium and supercritical carbon dioxide closed-cycle gas turbine systems, liquid-metal Rankine topping cycles, open- and closed-cycle inert-gas and liquid-metal magnetohydrodynamic (MHD) systems, and high- and low-temperature fuel cells.

Based on the results of the Phase 1 parametric analyses, the Interagency Steering Committee selected 11 concepts for more-detailed evaluation in Phase 2. These included steam systems with both atmospheric- and pressurized-fluidized-bed boilers; combined-cycle gas

turbine/steam systems with integrated gasifiers or fired by semiclean fuel; a potassium/steam system with a pressurized-fluidized-bed boiler; a closed-cycle gas turbine/organic system with a high-temperature, atmospheric-fluidized-bed furnace; a direct-coal-fired, open-cycle MHD/steam system; and a molten-carbonate fuel cell/steam system with an integrated gasifier.

The Phase 2 contractor studies were conducted by teams led by General Electric, Westinghouse, and United Technologies/Burns and Roe and were supplemented by NASA Lewis Research Center analyses and evaluation. Focus on a relatively small number of advanced energy conversion concepts in Phase 2 permitted technical and economic evaluation to be made in much greater depth than was possible in the Phase 1 parametric analyses.

After each phase the contractors' results were published and a report was prepared by NASA that summarized, compared, and evaluated the contractors' results. This report is an overall summary of ECAS. The two NASA reports summarized in this report were authored by numerous individuals at the Lewis Research Center. These reports were edited and compiled into their final form by Lloyd I. Shure (NASA Lewis Project Manager), Robert P. Migra, Raymond K. Burns, Donald C. Guentert, and Gerald J. Barna. The authors of the individual sections of the NASA reports were, in alphabetical order, M. Murray Bailey, Gerald J. Barna, Donald E. Benedict, Donald G. Beremand, William J. Brown, James A. Burkhart, Raymond K. Burns, Richard H. Cavicchi, Yung K. Choo, Robert L. Davies, Richard M. Donovan, Robert L. Dreshfield, Salvatore J. Grisaffe, Donald C. Guentert, Henry J. Hettel, Paul T. Kerwin, John L. Klann, William L. Maag, Robert P. Migra, Joseph J. Nainiger, Lester D. Nichols, George R. Seikel, Ronald J. Sovie, Robert J. Stochl, Harold H. Valentine, Marvin Warshay, and Jerry M. Winter.

2.0 INTRODUCTION

2.1 BACKGROUND

The Energy Conversion Alternatives Study (ECAS) was undertaken by NASA for the National Science Foundation (NSF) and the Energy Research and Development Administration (ERDA). This study had as its primary goal the identification and comparison of national options for the future generation of electricity from coal and coal-derived fuels in baseload service. It was an integrated government-industry effort that combined the funds of three agencies: NSF, ERDA, and NASA; the cooperation of the Department of the Interior and the Environmental Protection Agency (EPA); and the contracted expertise and experience of the Westinghouse Electric Corp., the General Electric Co., and the United Technologies Corp.,/ Burns and Roe, Inc. Supporting studies and overall coordination were provided by NASA's Lewis Research Center.

The objectives of ECAS were to provide information, at a comparable level of detail, that would enable an impartial evaluation of a variety of advanced baseload electric utility powerplant concepts that can use coal or coal-derived fuels and to define the relative potential of these concepts for meeting the nation's future electrical generating needs and environmental constraints. For each powerplant concept the study provides estimates of the overall efficiency (coal pile to bus bar) in converting coal to electricity, the powerplant capital costs, the cost of electricity, the environmental intrusion, and the resources and time required to bring the powerplant to a state of readiness for commercial service.

The concepts examined in ECAS were as follows:

- (1) Advanced steam
- (2) Open-cycle gas turbine
- (3) Combined-cycle gas turbine/steam turbine
- (4) Closed-cycle gas turbine
- (5) Open-cycle magnetohydrodynamic (MHD)
- (6) Closed-cycle, inert-gas MHD
- (7) Liquid-metal MHD
- (8) Supercritical carbon dioxide
- (9) Liquid-metal Rankine
- (10) Fuel cells

2.2 APPROACH AND SCOPE

The study was conducted in two phases.

Phase 1 - parametric analysis

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Phase 2 - conceptual design and implementation assessment

The study logic was to evaluate all energy conversion systems on a parametric basis in Phase 1 in order to provide an indication of each system's potential. From the resulting data base the most attractive systems could be delineated and selected for more-detailed conceptual design in Phase 2. These conceptual designs would provide the level of detail required to meaningfully assess factors that might affect commercial acceptance, as well as a better basis for estimating powerplant cost and performance.

Overall guidance for the study was provided by an Interagency Steering Committee consisting of members of each of the participating agencies. Two advisory panels assisted the Interagency Steering Committee - a Technical Advisory Panel consisting of representatives of each participating agency and a Utility Advisory Panel having members from electric utilities, the Electric Power Research Institute, and the Sierra Club. The organization is shown in figure 1 and the committee members are listed in table I.

In Phase 1, emphasis was placed on broad coverage of the energy conversion systems over wide ranges of parametric conditions. Approximately 900 parametric points were calculated by two contractor teams, one led by the General Electric Co. and one by the Westinghouse Electric Corp. The results were then compared and evaluated by NASA. The parallel-contract approach was selected in order to involve major suppliers of electric utility equipment and subcontractors or corporate groups familiar with each system concept, as well as architect-

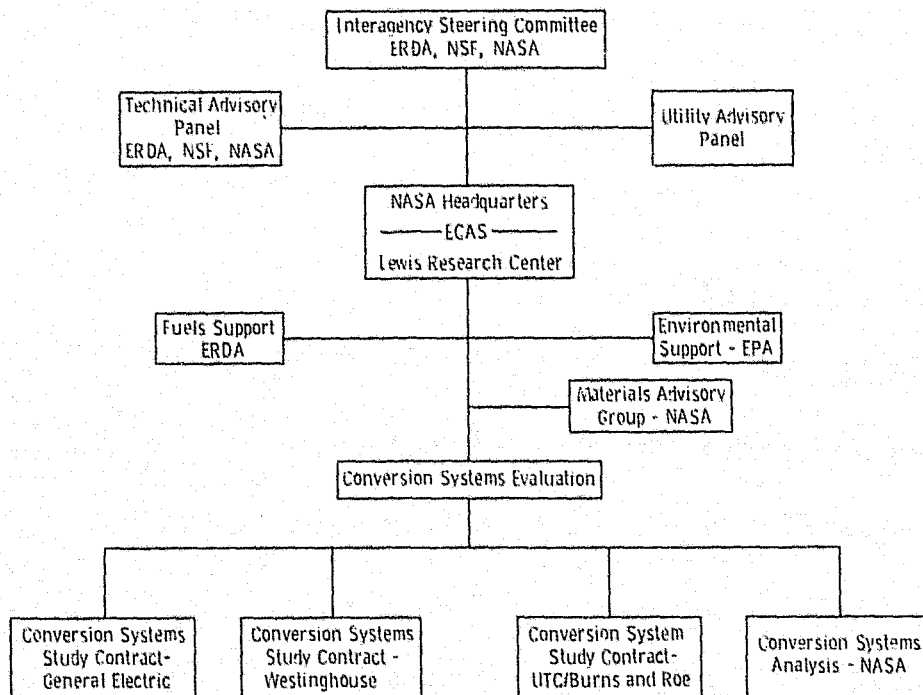


Figure 1. - Organization of Phase 2 Energy Conversion Alternatives Study (ECAS).

TABLE I. - PARTICIPANTS IN ENERGY CONVERSION ALTERNATIVES STUDY (ECAS)

Level of organization	Component	Members
Program	Steering Committee	D. Senich, Chairman (NSF) R. Zahradnik (ERDA) L. Topper (NSF) S. Freedman (ERDA) D. Ginter (NASA Headquarters) M. Ault (NASA Lewis) R. Schoen, Executive secretary (NSF) S. Gage, Observer (EPA/ORD) ^a J. Sullivan, Observer (OMB) ^a
	Technical Advisory Panel	J. Lynch, Chairman, Phase 1 (ERDA) ^a W. Crim, Chairman, Phase 2 (ERDA) J. Belding (ERDA) R. English (NASA Lewis) G. Manning (ERDA) ^b
	Utility Advisory Panel	C. Falcone, Chairman, Phase 1 (American Electric Power) ^a H. Phillip, Chairman, Phase 2 (Niagara Mohawk Power) R. Dunlop (American Electric Power) ^b R. Huse (Public Service Gas & Electric) R. Dunham (Tennessee Valley Authority) J. Agosta (Commonwealth Edison of Chicago) V. Cooper (Electric Power Research Institute) A. Rosenberg (Consolidated Edison of New York) R. Curry (Sierra Club Research Office)
	NASA Program Manager	P. Miller (NASA)
Project	NASA Lewis Project Managers	L. Shure R. Migra, Deputy
	Consultants	M. Schlesinger (ERDA) D. Walters (EPA) S. Grisaffe, Materials Advisory Group (NASA Lewis)

^aMember for Phase 1 only.^bMember for Phase 2 only.

engineer firms. It was anticipated that each contract team would use somewhat different design approaches that could lead to real and valid differences in the results. Common ground rules were provided, and each contractor analyzed the systems at a comparable level of power-plant detail. This permitted the differences in design approach, philosophy, and technical assumptions to be isolated for review and comparison. The contractor Phase 1 results are reported in references 1 and 2. A comparative evaluation of the Phase 1 results from ECAS is reported in reference 3.

Based on the results of the Phase 1 parametric analyses, the Interagency Steering Committee selected 11 concepts for more-detailed evaluation in Phase 2. The Phase 2 contractor

studies were conducted by teams led by General Electric, Westinghouse, and United Technologies/Burns and Roe and were supplemented by Lewis Research Center analyses and evaluation.

The systems selected by the Interagency Steering Committee for study in Phase 2 and assigned to the three contractors are shown in table II. The systems were selected from Phase 1 with emphasis on their potential for low cost of electricity (COE) and/or high overall efficiency. Further consideration was given to contractor capability and the need for making direct comparisons in assigning systems. Table II also includes some of the pertinent operating parameters for the selected systems.

The Phase 2 effort consisted of preparation of conceptual designs, research and development plans, and an implementation assessment of the selected systems. The assumptions used for the conceptual designs concerning component performance parameters, design approaches and/or configurations, etc., were estimates of the characteristics of a mature-technology powerplant. The research and development plans and implementation assessment then addressed the time and funding required to bring the technology for each powerplant to a state

TABLE II. - SCOPE OF ECAS PHASE 2

General Electric/Bechtel	Westinghouse/C. T. Main	UTC/Burns and Roe
Systems studied		
PFB/steam (3500 psig/1000 ⁰ F/1000 ⁰ F) ^a	PFB/steam (3500 psig/1000 ⁰ F/1000 ⁰ F) ^a	
AFB/steam (3500 psig/1000 ⁰ F/1000 ⁰ F) ^a		
Low-Btu gasifier/gas turbine/steam combined cycle (air-cooled turbine with inlet temperature of 2400 ⁰ F) ^b	Low-Btu gasifier/gas turbine/steam combined cycle (air-cooled turbine with inlet temperature of 2500 ⁰ F) ^c	Low-Btu gasifier/molten-carbonate fuel cell/steam
Semiclean-fuel-fired gas turbine/steam combined cycle (water-cooled turbine with inlet temperature of 3000 ⁰ F) ^b	Semiclean-fuel-fired gas turbine/steam combined cycle (ceramic blades and vanes; turbine inlet temperature of 2500 ⁰ F) ^c	
Coal-fired open-cycle MHD/steam (2500 ⁰ F direct air preheat)		
PFB/potassium/steam system (1400 ⁰ F potassium inlet temperature)		
AFB/closed-cycle gas turbine/organic (1850 ⁰ F turbine inlet temperature)		

^a R&D plans and implementation assessment not done for steam systems, advanced furnaces, or gasifiers.

^b At the first-stage rotor inlet.

^c At the first-stage stator inlet.

of readiness for commercial service, the probability of development success, the technological issues, and other factors that might influence the commercial acceptability and hence implementation of each powerplant. The contractors' Phase 2 results are reported in references 4 to 6, and all the Phase 2 results are summarized and compared in reference 7.

It was recognized that each of the systems covered by ECAS had been to some extent previously investigated. However, they had not been examined collectively on a consistent and comparable basis. In addition, the emphasis in ECAS was on total powerplant design, performance, and cost. This includes advanced combustion and/or gasification processes and equipment and assures that all significant costs and auxiliary thermal and electrical loads are included. (However, the study was not intended to provide a comparison between these combustion or gasification processes independent of the particular power systems studied.) On this basis, together with programmatic constraints of time and resources, it was decided to exercise the collective judgment of industry and government and to use this base of information and experience from previous studies as a point of departure rather than to perform an optimization study for each of the candidates.

Thus, in Phase 1, on the basis of this background, a number of base cases were defined that were judged as representative of the potential for each candidate. In addition, a number of parametric variations from these base cases were investigated in order to define the sensitivity of both the systems' cost and performance to these parametric variations. These base and parametric cases were for the most part, emphasized differently in each contract in order to adequately cover the potential for each system. In many cases, further optimization could be expected to make some improvement. As part of the evaluation described in this report, guidance is provided for the focus of any future evaluation in order to improve the comparison. This parametric approach (Phase 1) did achieve its objective of providing a basis for selecting systems to be evaluated in more detail in Phase 2 of the ECAS study.

The Phase 2 conceptual designs permitted a better estimate of powerplant performance, COE, and environmental intrusion and served as the basis for estimating the resources and time required to bring the powerplant concept to commercial service. The powerplant concepts ranged from nearly state of the art to immature technologies. Each contractor defined the existing state of the art and addressed the immature technologies in a research and development (R&D) plan for each system. Resource and time estimates for each task within an R&D plan led to estimates of the year in which commercial availability could be achieved. Each contractor also completed an implementation assessment of each system according to technological, societal, and environmental factors. As noted in table II, research and development plans were not prepared for steam systems, advanced furnaces, or gasifiers. The focus and major effect in ECAS were on the energy conversion system, and it was not intended that sufficient detail be developed on the requisite furnace and gasifier subsystems to define all problem

areas. No R&D plans were requested for advanced steam, since for that system the primary advancement is in the furnace subsystem.

This report is a summary of the two NASA reports (refs. 3 and 7). In those two reports, the Phase 1 and 2 results were reviewed and compared. Results of supplementary analyses done at NASA are included to add additional perspective on the results and/or to reconcile differences in the results of different contractors. The ground rules in the study (both those specified by the government and those selected by the contractors) are given in the following section. The Phase 1 results are summarized in section 4.0 and those of Phase 2 are summarized in section 5.0. The overall perspective of the results is discussed briefly in section 6.0.

3.0 GROUND RULES AND PROCEDURES

3.1 FUELS AND FUEL COSTS

Three coals were specified for Phase 1:

- (1) Illinois #6 (3.9-percent sulfur and 10 788-Btu/lbm higher heating value (HHV))
- (2) Montana subbituminous (0.8-percent sulfur and 8944-Btu/lbm HHV)
- (3) North Dakota lignite (0.7-percent sulfur and 6890-Btu/lbm HHV)

These coals were recommended by ERDA because they represent a wide range of coal properties and all are abundant and readily available. The detailed specifications of these coals were provided to the contractors (ref. 3). In addition, many of the parametric variations

TABLE III. - ECAS FUEL COST AND EFFICIENCY ASSUMPTIONS

Fuel type	Base fuel cost (delivered), \$/MBtu	Conversion efficiency	
		General Electric	Westinghouse
Coal:			
Illinois #6	0.85	----	----
Montana subbituminous	.85	----	----
North Dakota lignite	.85	----	----
High-Btu gas	2.00	0.50	0.67
Intermediate-Btu gas	2.10	.70	.84
Low-Btu gas	(a)	(a)	(a)
Hydrogen	2.50	.61	.56
Liquid (distillate)	2.60	.56	.51
Methanol	2.70	(b)	.70
Semiclean (solvent-refined coal)	1.80	^c .78	(b)

^aAlways integrated.

^bNot used.

^cRevised downward to 0.74 in final reading by G. E.

(b) Phase 2

Fuel type	Base fuel cost (delivered), \$/MBtu	Conversion efficiency from coal
Illinois #6 coal	1.00	----
Semiclean fuel (II-coal)	2.25	0.74
Intermediate-Btu gas ^a	2.25	.62

^aUsed only for seed reprocessing in MHD/steam system.

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in Phase 1 involved the use of coal-derived fuels. These include high-, intermediate-, and low-Btu gas, liquid distillate, semiclean solvent-refined coal (SRC), hydrogen, and methanol.

In Phase 2, only two fuels were selected. The Illinois #6 coal was used in nine of the conceptual designs and semiclean fuel derived from coal in the H-coal process was used in two of the conceptual designs. The H-coal semiclean fuel specifications (details in ref. 7) include a higher heating value of 16 700 Btu/lbm, a sulfur content of 0.48 percent, and a nitrogen content of 1.3 percent.

The specified fuel costs are listed in table III. In addition to the fuels shown, some of the parametric variations in Phase 1 included the use of oxygen. The specified price of oxygen was \$9/ton. Dolomite and limestone were assumed to cost \$5/ton in both phases. Also shown in table III are the fuel conversion efficiencies assumed for each of the coal-derived fuels. These were used to determine the coal-pile-to-bus-bar efficiency of those powerplants that do not use coal directly or that do not include an integrated gasifier.

3.2 DEFINITION OF EFFICIENCIES CALCULATED

Three system efficiencies were calculated for each parametric case in Phase 1 and for each conceptual design in Phase 2: the thermodynamic efficiency, the powerplant efficiency, and the overall energy efficiency.

The thermodynamic efficiency is the gross electric power at the primary-cycle generator terminals divided by the heat input to the primary cycle. The primary cycle is defined as the power-producing portion of the system exclusive of any furnace or gasifier subsystem. The thermodynamic efficiency does not therefore include any power produced by pressurizing turbomachinery within a furnace system. It also does not include the effects of auxiliary power requirements, transformer losses, losses of a furnace subsystem (which include stack losses), losses in a gasification subsystem, or losses in any off-site fuel conversion process.

The powerplant efficiency is defined as the net electrical power output from the entire powerplant divided by the higher heating value of the fuel input to the entire powerplant. It therefore includes the effects of all the items that were excluded from the thermodynamic efficiency except the off-site fuel conversion losses. The net power delivered was specified as 500-kilovolt, 60-hertz alternating-current power. In some parametric variations in Phase 1, smaller powerplants were studied at lower voltages.

The overall efficiency is the coal-pile-to-bus-bar efficiency, which includes any off-site fuel conversion efficiency. The powerplant and overall energy efficiencies are identical for those powerplants that use coal directly or have integrated gasifiers.

3.3 CAPITAL COST BASIS

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All capital costs were to be estimated in terms of mid-1974 dollars in Phase 1. In Phase 2 this was revised to mid-1975 dollars. During the powerplant construction period the capital cost is increased by applying an escalation factor of 6.5 percent per year on unused funding and an interest rate of 10 percent per year compounded quarterly on committed funding. The actual cost escalation and interest charges depend on the cash flow required during the construction period. An S-shaped cash flow curve (ref. 8) was specified for both Phases 1 and 2. In Phase 1, each of the contractors applied this curve and obtained slightly different results because of differences in the method of numerical integration. Therefore, in Phase 2, the calculation was done at NASA and the contractors were supplied with the factors to be applied as a function of the length of the construction period. In using this approach and comparing powerplants with different construction periods, it was assumed that all had a common start-of-construction date.

3.4 LABOR RATE

A composite labor rate of \$10.60/hour, representative of a combined civil/mechanical/electrical rate, was used for all construction-site-labor hours in Phase 1 cost estimates. This was based on a survey of rates applicable to the utilities industry and was selected as a weighted average for a "Middletown, USA," construction site. In Phase 2 this composite labor rate was specified as \$11.75/hour.

3.5 ENVIRONMENTAL AND SITE CONDITIONS

A Middletown, USA, site was selected for the powerplants of ECAS. Powerplant performance was determined for average-day conditions of 59° F. The 5-percent summer environmental conditions were specified for this site for use in sizing and in estimating the cost of the heat rejection system. These conditions are as follows:

- (1) Cooling water temperature, 75° F
- (2) Air temperature (wet bulb), 77° F
- (3) Air temperature (dry bulb), 93° F
- (4) Ambient air pressure, 1.00 atmosphere

The emissions constraints specified for ECAS were established after consultation with EPA. These standards correspond to existing national emissions standards for fossil-fuel-fired steam-generating units of more than 250-million-Btu-per-hour heat input. The environmental intrusions in pounds of effluent per million Btu of heat input allowed for sulfur dioxide (SO₂), nitrogen oxides (NO_x), and particulates are as follows:

Pollutant	Fuel	Intrusion, lb/MBtu
SO ₂	Solid	1.2
	Liquid	.8
	Gaseous	.2
NO _x	Solid	.7
	Liquid	.3
	Gaseous	.2
Particulates	All fuels	.1

In Phase 1, parametric variations included use of wet and dry mechanical-draft cooling towers and once-through cooling. In Phase 2, all the conceptual designs used wet mechanical-draft cooling towers.

3.6 METHOD OF CALCULATING COST OF ELECTRICITY

The capital contribution to the cost of electricity (COE) was calculated from the powerplant capital cost (calculated as discussed in section 3.3), a specified powerplant capacity factor of 0.65, and an annual fixed charge rate of 0.18. The 18-percent fixed charge rate included the following items:

Item	Rate, percent/yr
Cost of money	7.5
Federal income tax	4.1
Depreciation	3.3
Other taxes	2.8
Insurance	.1
Working capital	.2
Total	18.0

The fixed charge rate was provided by the Utility Advisory Panel. The fuel contribution to COE was calculated from the specified fuel costs (table III) and powerplant efficiencies. The specified efficiency is that at design power level. Therefore, it is assumed implicitly that the powerplant operates at full power for a fraction of the calendar time equal to the assumed capacity factor. With the usual varying power demand from the plant, the average efficiency would be lower than this, and the additional fuel used would increase the COE somewhat.

The operating and maintenance (O&M) estimates were made separately by the contractors and include costs for operating labor, expendable supplies (including limestone or dolomite), labor and materials for continuing maintenance, and labor and materials for major-component interim replacements.

3.7 CONTRACTORS' COST-ESTIMATING PROCEDURES

The approaches to estimating total capital costs were similar for each contractor team. Each team included an architect and engineering (A&E) firm experienced in powerplant construction. A team member or subcontractor provided cost estimates of the major equipment for each powerplant as delivered to the site. The A&E estimated the cost of all labor and material to erect and/or complete the major components as well as the balance of plant. The contractor team then added factors for indirect labor, A&E services, and contingency to the direct labor and material cost estimates. These factors are compared in table IV. The total capital cost of each system was then determined by applying the escalation and interest factor to the total labor and material estimates, including the added factors of table IV.

In both Phases 1 and 2, Bechtel Corp. acted as A&E for General Electric and C. T. Main, Inc., for Westinghouse. In Phase 2, Burns and Roe, Inc., provided this service for United Technologies Corp.

The cost elements listed in table IV are basically as follows:

(1) Direct - This is the basic cost developed as a dollar estimate for each major component or grouping of balance-of-plant (BOP) material or site labor identified for costing (cost account categories) in the powerplant.

(2) Indirect - A percentage factor applied to direct site labor costs, it accounts largely for labor-related costs such as supervision, field engineering, administration, medical services, overhead, payroll taxes, insurance, tools, equipment and supplies, and temporary construction facilities at the construction site.

(3) A&E services - A percentage factor to account for the design, engineering, procurement, and construction management services and the fee of the architect-engineer, it can be applied to all cost categories including major components or as a different percentage applied to only the BOP material and site labor.

(4) Contingency - A percentage factor on all cost categories, it accounts for the money, man-hours, and time that must be added to the estimate to compensate for uncertainties in the details of quantity, pricing, and productivity and variations in the other cost elements of the estimate. For conventional powerplants, the contingency is money that experience has shown will be spent. Contingency reflects a selected risk of overrun. Contingency does not provide for changes in the defined scope of a project or for unforeseen circumstances beyond normal experience or control.

TABLE IV. - POWERPLANT CAPITAL COST PROCEDURES^a

(a) Phase 1

Cost	G. E./Bechtel			Westinghouse/C. T. Main		
	Major-components material	Balance of plant		Major-components material	Balance of plant	
		Site material	Site labor		Site material	Site labor
Direct, dollars	\$	\$	\$	\$	\$	\$
Indirect, percent of direct	---	---	×90	---	---	+51
A&E services, percent of direct and indirect	---	×15	×15	+8	+8	+8
Contingency, percent of direct, indirect, and A&E services	×20	×20	×20	^c +8	^c +8	^c +8

(b) Phase 2

Cost	G. E./Bechtel			Westinghouse/C. T. Main			UTC/Burns and Roe		
	Major-components material	Balance of plant		Major-components material	Balance of plant		Major-components material	Balance of plant	
		Site material	Site labor		Site material	Site labor		Site material	Site labor
Direct, dollars	\$	\$	\$	\$	\$	\$	\$	\$	\$
Indirect, percent of direct	---	---	×90	---	---	×51	---	---	×90
A&E services, percent of direct and indirect	---	×15	×15	×10	×10	×10	×10	×15	×10
Contingency, percent of direct, indirect, and A&E services	×20	×20	×20	^d ×10	^d ×10	^d ×10	×7.5	×10	×20

^aThe symbols × and + indicate the contractor's method of applying the percentage factors to a direct base of 1.0.

For example, G. E./Bechtel site labor, $1.0 \times 1.9 \times 1.15 \times 1.20 = 2.62$ or 262 percent of the direct; Westinghouse/C. T.

Main site labor, $1.0 + 0.51 + 0.08 + 0.08 = 1.67$ or 167 percent of the direct.

^bThe dollar value that is the basic estimating variable. The content of "direct" is not the same among the contractors.

^cBased on a 5-yr design and construction period and the formula 3 percent plus 1 percent per year.

^dSeven percent for semiclean-fuel-fired plant.

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Each contractor team added indirect labor costs as they applied to site labor only. The lower indirect labor factor (51 percent) of Westinghouse/C. T. Main is representative of an A&E who tends to subcontract a large part of the labor required. The G.E./Bechtel and UTC/Burns and Roe indirect labor factors are representative of construction with their own labor forces. Although the factors for A&E services do vary for the three teams, there is no really significant effect on capital costs. The difference in contingency factor has a substantial effect on capital costs after escalation and interest. Each contractor expects that the contingency will be spent in constructing the powerplant. Therefore, contingency should not be arbitrarily discarded when making comparisons. The capital cost estimates of the three contracting teams may represent different probabilities of overrun, but in each system they represent their estimate of expected powerplant costs.

4.0 PHASE 1 RESULTS

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As described previously, over 900 parametric cases were analyzed in Phase 1. These parametric cases were selected on the basis of information received from the agencies sponsoring the study, from each of the prime contractors, and from the various groups that acted as advocates for each of the systems. Each of these systems had been previously studied on various bases and to different extents. Thus, it was anticipated that each advocate or concept group familiar with each system could select design points (base cases) and variations about these base cases that would indeed represent each system to its maximum potential. In addition, to enhance the value of the study, in some cases, breadth of coverage was emphasized, with a limited overlap between contractors for comparison. As a result, the parametric points evaluated by each contractor have in many cases substantially different emphases.

In this section the overall efficiency and cost of electricity results for all the systems are summarized and compared. The separate results for each system are summarized briefly in appendix A. There the ranges of parameters and areas of emphasis of each contractor are described for each system. And the most attractive cases are identified and discussed. It is not practical to discuss all the results in this summary report. In addition to the overall and powerplant efficiencies, the total capital cost, and the cost of electricity, the contractors reported cost breakdowns that included costs of major components for each parametric case. For the base cases, the thermodynamic state points, environmental intrusions, and natural resource requirements were also reported. These results are discussed in more detail in reference 3. Each system was to meet the environmental standards discussed in section 3.5; but, at the level of detail appropriate to the Phase 1 parametric analysis, the emissions results should be regarded as nominal estimates. The Phase 2 analysis provides more opportunity for considering these factors (section 5.0).

In reviewing the results of Phase 1, it is important to recognize that limited design detail was generated, particularly with respect to the powerplant because the emphasis was on parametric analytical comparison. It can, consequently, be assumed that further detailed powerplant layout and integration could in many cases enhance both confidence in cost projections and performance estimates. This is the objective of Phase 2 and forms the basis for the study logic. The data, particularly with respect to cost, are more meaningful on a relative basis than on an absolute basis. Also, as a result of the approach used, the parametric cases were chosen at the beginning of the study and there was little opportunity for modifying the selection during Phase 1. Phase 1 was not an optimization study for each of the concepts but rather was an evaluation based on previous experience or familiarity with the various concepts. But the breadth of coverage and results was sufficient to provide a basis for evaluating system potential and selecting the most promising concepts. Within these limits, Phase 1 achieved its objectives:

- (1) It did provide a clear basis for selecting systems for Phase 2 conceptual design.
- (2) It did provide a basis from which to proceed to the conceptual design of powerplants that would exploit the potential of the selected systems with more attention to plant design.
- (3) It did define those factors in need of more-detailed examination in order either to make those systems not selected more attractive or to confirm the basis for their exclusion.
- (4) As a result of the display of ground rules, methodology, assumptions, and data format, it did provide a common basis upon which advocates of the various systems and others can make future comparisons.

4.1 OVERALL COST AND PERFORMANCE COMPARISONS

The ranges of overall energy efficiency, powerplant efficiency, and cost of electricity obtained for most parametric cases of each system are shown in figures 2 and 3. In each case the General Electric results are plotted in part (a) and the Westinghouse results in part (b). When the results for two different powerplant configurations or two different fuels are substantially different, more than one ellipse is used to define the range of results for that system.

The ellipses approximate the actual ranges of results, which are shown in more detail in reference 3. The size and location of these ellipses are, of course, a function not only of the procedures and assumptions made in the calculations, but also of the choice of the study ground rules and the system parameters and ranges of parameters examined. For some systems the areas of emphasis, ranges of parameters, or system configurations examined by the contractors differed. These are described in the individual system discussions in appendix A.

An objective of this study is to compare power systems on the basis of their efficiency in the use of coal. Emphasis has therefore been placed on the overall energy efficiency, which includes the efficiency of the conversion of coal into a cleaner fuel for those systems that do not use coal directly. One of the initial assumptions made by the contractors was the fuel conversion efficiency in obtaining a clean or semiclean fuel from coal. In some cases the contractors have used different fuel conversion efficiencies for the same or similarly processed fuels. As a result their overall energy efficiencies for some systems may be substantially different even though their powerplant efficiencies agree. In such cases the contractors' power system results can be more validly compared on the basis of powerplant efficiency. Both overall energy efficiency and powerplant efficiency have been presented.

The various systems can be arranged into three groups according to whether they combust coal directly, include an integrated coal gasifier and combust the fuel gas, or use a fuel processed from coal off-site and delivered "over the fence." The results in figure 2 can be partly understood from this perspective, and this is discussed as appropriate for the individual systems in appendix A. Some of the systems considered in Phase 1 include parametric variations that fall into more than one of these groups. The systems that can combust coal directly

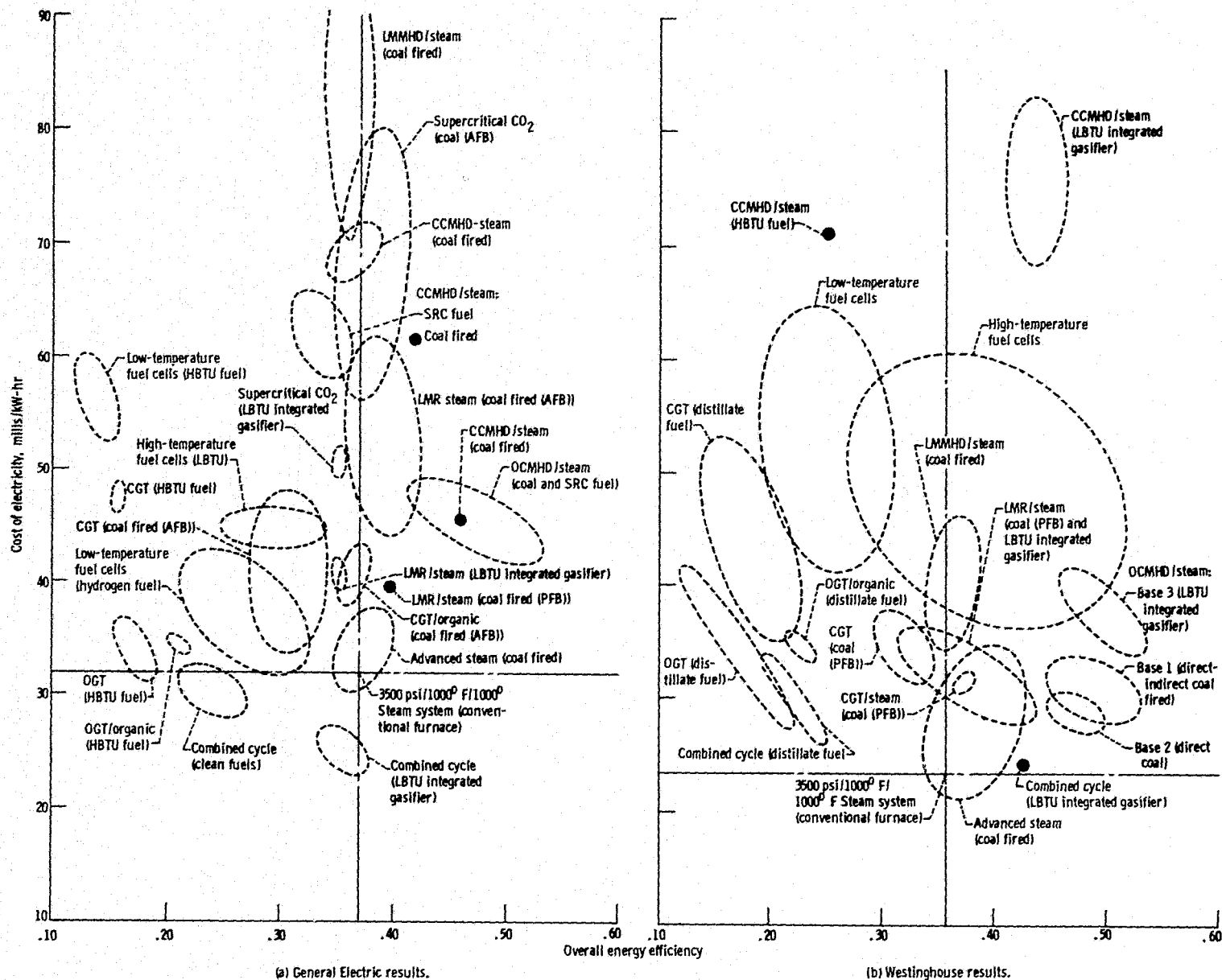


Figure 2. - Overall efficiency and COE results using ECAS ground rules (Phase 1).

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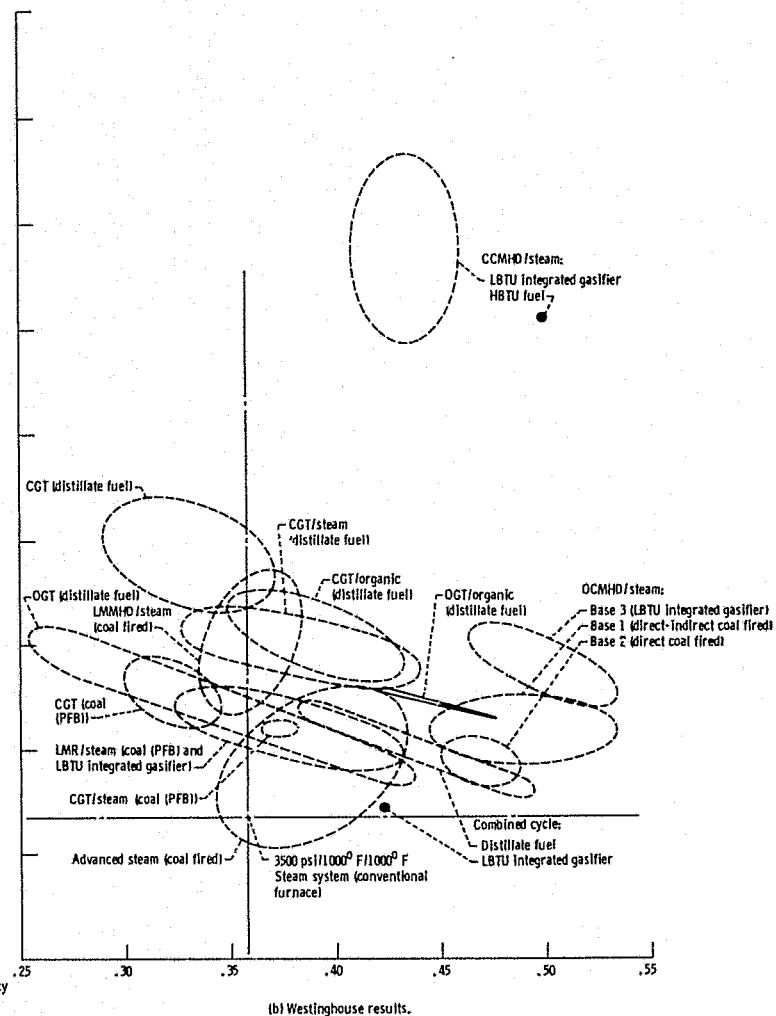
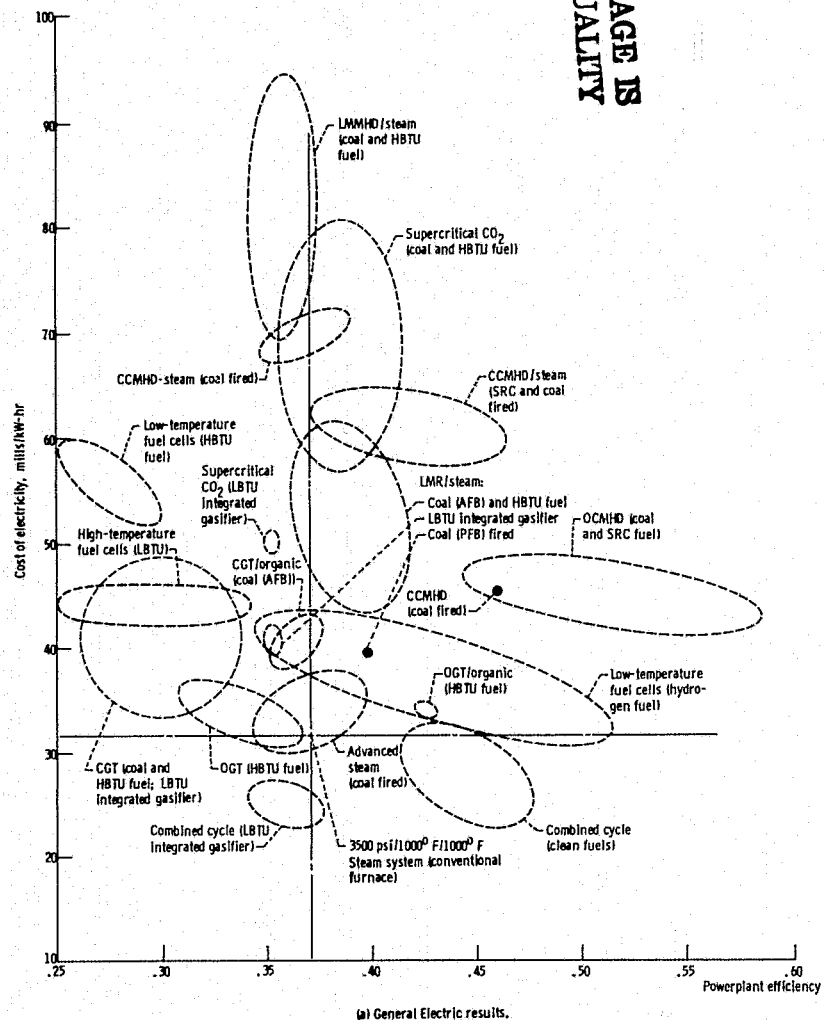


Figure 3. - Powerplant efficiency and COE results using ECAS ground rules (Phase 1).

avoid the losses of an integrated gasifier or an off-site fuel conversion process. However, most of these are closed-cycle systems and hence are limited in primary-cycle peak working temperature by the capabilities of the furnace heat exchanger. They also cannot avoid the losses of the furnace subsystem. With a stack temperature of about 300°F the furnace subsystem is able to transfer only 85 to 90 percent of the heat released by the coal to the primary power cycle. The open-cycle systems can reach higher powerplant efficiencies by using higher peak temperatures. Except for possibly the open-cycle MHD system, the open cycles (and the fuel cell system) require cleaner or processed fuels. An integrated gasifier processes fuel at a higher effective efficiency than does an off-site fuel conversion process and hence yields a higher overall energy efficiency. However, the gasifier subsystem is at least as complex and expensive as the furnace subsystem of the closed-cycle systems.

The use of an off-site-processed fuel usually results in a lower capital cost system but at the expense of higher fuel cost and probably lower overall efficiency because of the fuel conversion efficiency. Comparing figures 2 and 3 shows that even though the powerplant efficiencies of either combined cycles using clean fuels or low-temperature fuel cells using hydrogen, for example, exceed that of a steam plant, the overall energy efficiency, which includes the fuel conversion efficiency, is lower. For combined-cycle gas turbine/steam turbine systems, the results of both contractors show that using an integrated low-Btu gasifier resulted in the best trade-off between these two effects and hence in the lowest COE and highest overall energy efficiency.

According to both contractors, the open- and closed-cycle inert-gas MHD systems and the liquid-metal-Rankine/steam system exceeded 40 percent overall energy efficiency. Each contractor also had another system with greater than 40 percent overall efficiency: for G.E., the supercritical carbon dioxide system; for Westinghouse, some high-temperature fuel cell cases. In all these cases, the COE exceeded that for a 3500-psi/ 1000°F / 1000°F steam plant with a conventional coal-fired boiler. However, Westinghouse calculated one parametric case for the combined cycle with an overall energy efficiency above 40 percent and a COE very near that of the conventional steam plant.

In both contractors' results, the steam systems, combined cycles, liquid-metal MHD, closed-cycle gas turbine, and high-temperature fuel cells generally fall in the 30- to 40-percent range of efficiency. The clean-fueled gas turbine systems and the low-temperature fuel cells using clean over-the-fence fuels fall below this range, although in terms of powerplant efficiency, some of the parametric cases exceed 40 percent. The efficiency and COE results are discussed more specifically and the results of the two contractors compared in appendix A.

4.2 SENSITIVITY OF RESULTS TO GROUND RULES

The results discussed in the previous section are a function not only of the technical results from the contractors, but also of the economic ground rules specified (section 3.0) for the study. The technical results have been reported in sufficient detail to allow recalculation of such parameters as COE for alternative ground rules. This was done in reference 3 for the Phase 1 results. The effects on COE of changes in the assumed fuel cost, fixed-charge rate, capacity factor, and interest and escalation rates were calculated. In general the conclusion was that the relative results did not change so substantially as to affect selections for Phase 2 when each parameter was varied separately over relatively wide ranges.

The method of calculating COE was also varied. The application of interest and escalation to the capital costs during the construction period, as described in section 3.3, results in total capital cost in terms of dollars of a year other than the base year, mid-1974. If construction had been started in mid-1974, the addition of interest and escalation in this manner would lead to a total cost that could be viewed as the indebtedness in the year the powerplant would come on line, or the capital cost in dollars of that year. Since the various powerplants have different construction periods, this results in the capital cost totals being in dollars of different years. One of the variations in ground rules examined was to deescalate the capital cost totals to again express them in terms of mid-1974 dollars. This is referred to as the cost in "constant mid-1974 dollars," which as used herein refers to dollars actually expended over a period of time but expressed in terms of mid-1974-dollar purchasing power. The total still reflects the length of the construction period in that it includes the interest paid in excess of the escalation rate (as affected by the cash flow curve).

The COE's that result from using the capital cost totals in constant mid-1974 dollars are shown in figure 4 for selected cases for each system. The selected parametric cases, in general, include the one with highest efficiency, lowest capital cost, and lowest COE for each system. The influence of this change in ground rule is greater for the higher capital cost systems, for which the capital contribution to COE is relatively larger. Also the higher capital cost systems tend to have longer construction periods; and the longer the construction period, the greater the effect of this change on the capital cost total. As shown in the figure, those systems that have higher efficiency but also higher capital cost look relative better under these ground rules. For example, in the Westinghouse results the open-cycle MHD system moved into the same range of COE as the advanced steam system.

Another variation in calculating COE considered was to average COE over the powerplant lifetime. In an inflationary period the more efficient systems would become more favorable economically through more efficient use of increasingly expensive fuels. These results are presented in reference 3. Also the Phase 2 results were used to calculate the COE according to this method and are summarized in section 5.1.

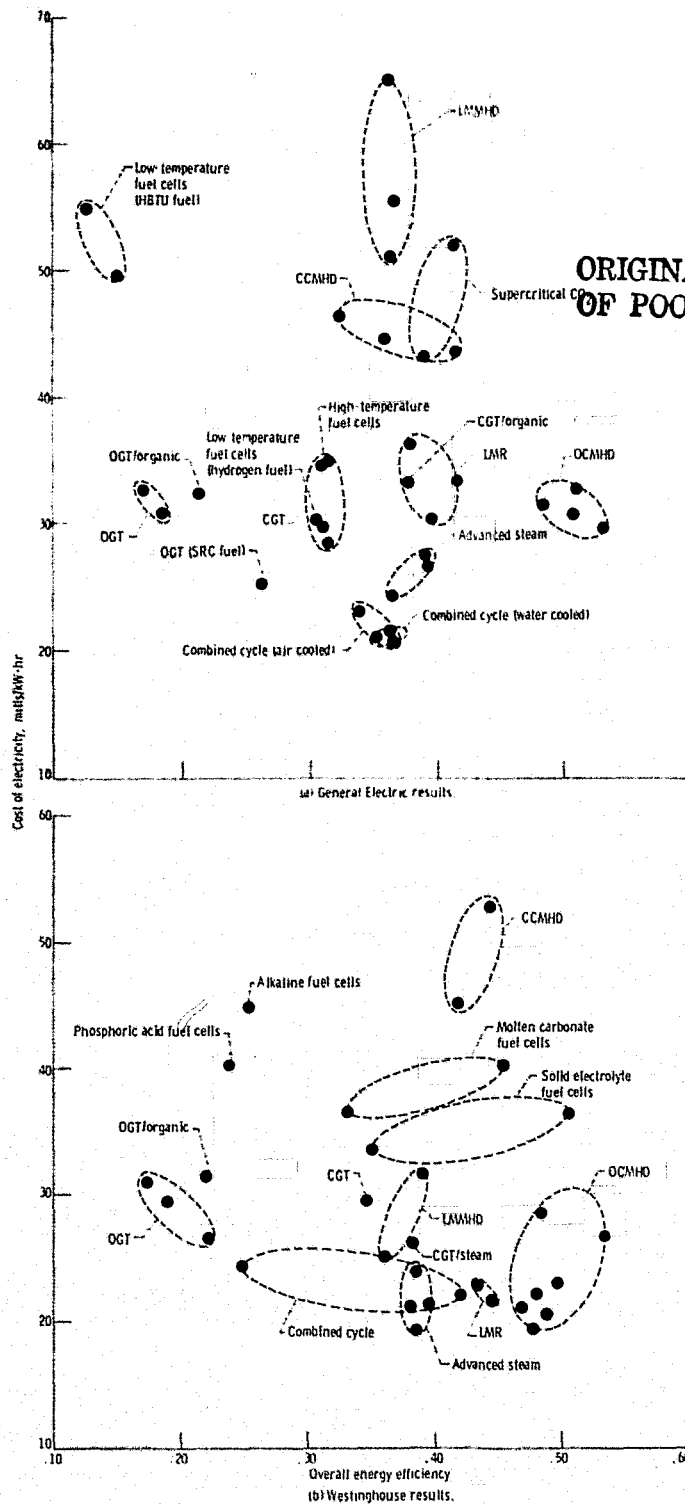


Figure 4. - Overall efficiency and COE results for selected parametric cases, constant mid-1974 dollars (Phase 11).

Although the variations presented herein have not been exhaustive, the economic assumptions are clearly important in assessing the results. Also, the ECAS parametric results can be used in many ways because the assumptions and data are clearly displayed and readily separable. Different comparisons can be made according to different economic assumptions without affecting the performance data and can provide additional perspectives on the relative competitiveness of the various systems.

4.3 SELECTION OF SYSTEMS FOR PHASE 2

Initially, the Interagency Steering Committee obtained recommendations from the Utility Advisory Panel, General Electric, and Westinghouse, as well as from the NASA Lewis project team. This was accomplished as a part of the public briefing following the Phase 1 presentation of results in May 1975. On the basis of these recommendations and the perspective obtained directly from the data presentation, the Interagency Steering Committee subsequently selected the systems for Phase 2 conceptual design, as shown in table II. The selection of systems was not constrained by any given time frame for commercial implementation but was instead influenced by the potential for deriving the greatest national benefit from advanced technologies showing the most promise for economical production of electricity and increased efficiency. This table also shows the assignment of these systems for study by each contractor, this assignment being based on programmatic considerations.

The fact that a system was not selected does not necessarily imply that no further consideration is warranted. Systems not selected generally fall into two categories:

- (1) Those systems for which the technology or design base was insufficient to permit, within given resource constraints, adequate treatment of the system at a conceptual design level
- (2) Those systems that could not be expected to show their maximum potential on a comparative basis for the study emphasis, which is primarily large, central-station base-load powerplants

5.0 PHASE 2 RESULTS

At the end of Phase 1, the Interagency Steering Committee selected 11 concepts for more-detailed evaluation in Phase 2 (section 4.3). In Phase 2, conceptual designs were prepared and costs estimated with the assumption that for each concept the technology had reached commercial maturity. Preliminary research and development plans were then prepared by the contractors to estimate the time and funding required in each case to bring the technology to commercial readiness. An implementation assessment was also made for each system to examine other factors that would affect its implementation for utility service. The results of the conceptual designs are the subject of sections 5.1 and 5.2. The research and development plans and implementation assessments are discussed in sections 5.3 and 5.4, respectively. In parallel with Phase 2, G.E. also did a conceptual design of a steam system with a conventional pulverized-coal furnace and wet-lime stack-gas scrubbers. This was done on the same basis and with the same ground rules used for ECAS. It was funded by the Tennessee Valley Authority and the Environmental Protection Agency. The results are briefly summarized in appendix B. The overall results are also shown in the figures in section 5.1 as a comparison with the results for the ECAS systems.

It is important to remember in comparing the conceptual designs that they represent different levels of technology. In large part, the level of technology for each case was implicitly assumed at the start of Phase 2 by the specification of such parameters as peak temperature and pressure or the choice of system configuration, fuel type, gasifier type, type of turbine cooling, and the level of performance of the fuel cell or the MHD generator. The performance and cost estimates for the Phase 2 cases are, of course, significantly influenced by these initial assumptions.

Further, it is important to consider that, although the Phase 2 conceptual designs were all done to comparable levels of detail, with common ground rules, and with the assumption that each had reached a state of commercial maturity, the uncertainties of the conceptual design results differ from system to system. The more distant the expected date of commercial maturity, or the more immature the present technological status of a system, the more difficult it is to estimate the component or subsystem performance characteristics and cost. In the more near-term systems, these uncertainties are mainly uncertainties in the cost of a particular component or subsystem, such as the atmospheric fluidized bed in the AFB/steam system. But in the more-advanced systems or those in which the present technology is more immature, these uncertainties extend not only to a larger fraction of the components but to the system performance as well. The effect of capital cost uncertainties on the comparisons of the conceptual design results was examined in reference 7 and is summarized in section 5.4. The differences in the present states of technology are reflected in the time and money required for development, which are discussed in section 5.3.

5.1 OVERALL COMPARISON OF CONCEPTUAL DESIGNS

The overall performance and cost results of all the Phase 2 conceptual designs are listed in table V(a). The environmental intrusions and natural resource requirements are summarized in table V(b). These results are compared on an overall basis in this section and on a system-by-system basis in section 5.2.

The three efficiencies shown in table V(a) are those defined for the study (section 3.2). The capital cost estimates and costs of electricity are shown for both the ECAS ground rules (sections 3.3 and 3.6) and in terms of constant mid-1975 dollars. According to the ECAS ground rules, interest and escalation during construction were added by using a specified S-shaped cash flow curve. The cost estimates before the interest and escalation were added were in terms of mid-1975 dollars. After the addition of construction-period interest and escalation, however, the cost total can be viewed as the indebtedness in the year the powerplant goes on line, if construction begins in mid-1975.

Therefore, the capital cost totals in table V(a) for ECAS ground rules are in terms of the dollars of the year construction would be completed if it had been started in mid-1975. But since the estimated construction periods vary from 4 to 6.5 years, the year of completion varies from mid-1979 to 1982. And the COE shown for ECAS ground rules were calculated by using this capital cost and the mid-1975 O&M costs and specified fuel prices.

The capital costs listed in table V(a) that are labeled "constant mid-1975 dollars" were obtained by deescalating the "ECAS ground rule" totals by the 6.5 percent escalation rate over the construction period. The term "constant mid-1975 dollars" as used herein refers to dollars that are expended over a period of years during powerplant construction but that are expressed in terms of the purchasing power of mid-1975 dollars. However, the competitive positions of the systems are not significantly changed from what is shown by the results listed in the "ECAS ground rule" column.

TABLE V. - SUMMARY OF ECAS PHASE 2 RESULTS

(a) Performance and cost results

System and contractor	Net power, MW	Efficiency, percent			Construction period, yr	Capital cost, \$/kWe			Cost of electricity, mills/kW-hr	
		Thermodynamic	Power-plant	Overall		For power-plant without interest and escalation ^a	For ECAS ground rules ^b	For constant mid-1975 dollars ^c	For ECAS ground rules	For constant mid-1975 dollars
1 - AFB/steam (General Electric)	814	43.9	35.8	35.8	5.5	408	632	447	31.7	25.8
2 - PFB/steam (General Electric)	904	41.3	39.2	39.2	5.5	467	723	511	34.1	27.4
3 - PFB/steam (Westinghouse)	679	42.3	39.0	39.0	5.0	369	549	401	28.1	23.5
4 - PFB/potassium/steam (General Electric)	996	47.8	44.4	44.4	5.5	603	934	660	39.9	31.2
5 - AFB/closed-cycle gas turbine/organic (General Electric)	476	50.1	39.9	39.9	5.0	829	1232	899	49.3	38.8
6 - Low-Btu gasifier/gas turbine/steam (General Electric)	585	44.2	39.6	39.6	5.0	518	771	562	35.1	28.6
7 - Low-Btu gasifier/gas turbine/steam (Westinghouse)	786	48.5	46.8	46.8	5.0	413	614	448	29.1	23.9
8 - Semiclean-fuel-fired gas turbine/steam (Westinghouse)	874	53.6	52.2	38.6	4.0	239	329	256	26.0	23.7
9 - Semiclean-fuel-fired gas turbine/steam (General Electric)	847	52.7	51.1	37.8	5.0	281	418	305	29.5	25.9
10 - Coal/MHD/steam (General Electric)	1932	54.0	49.8	48.3	6.5	429	720	478	31.8	24.1
11 - Low-Btu gasifier/molten-carbonate fuel cell/steam (United Technologies Corp.)	635	53.6	49.6	46.6	5.0	399	593	433	28.9	23.9

^aEstimated in terms of mid-1975 dollars.^bIncluding interest of 10 percent a year and escalation of 6.5 percent a year calculated for S-shaped cash flow curve during construction period.^cObtained by deescalating the "ECAS ground rule" total by 6.5 percent a year for construction period.

TABLE V. - Concluded.

(b) Emissions and natural resource estimates

System and contractor	Net power, MW	Emissions, lb/MBtu			Land, acre/100 MWe		Water, gal/kW-hr		Sorbent solid lb/kW-hr	
		Sulfur dioxide	Oxides of nitrogen	Particulates	Power-plant	Waste disposal	Input	Output	Input	Output
1 - AFB/steam (General Electric)	814	1.028	0.270	0.099	12.8	15	0.611	0.18	0.227	0.292
2 - PFB/steam (General Electric)	904	.688	.152	.100	12	14	.548	.16	.372	.342
3 - PFB/steam (Westinghouse)	679	.72	.30	.014	56	68	.707	.36	.296	.296
4 - PFB/potassium/steam (General Electric)	996	.688	.162	.100	10.9	.96	.416	.12	.329	.302
5 - AFB/closed-cycle gas turbine/organic (General Electric)	476	1.077	.363	.100	13.5	2.95	.510	.13	.205	.262
6 - Low-Btu gasifier/gas turbine/organic (General Electric)	585	1.20	.372	0	10.6	2.6	.416	.09	0	.103
7 - Low-Btu gasifier/gas turbine/steam (Westinghouse)	786	.91	.65	.014	47	63.6	.43	.22	.251	.245
8 - Semiclean-fuel-fired gas turbine/steam (Westinghouse)	874	.57	.6	.01	40.1	0	.38	.20	0	.0003
9 - Semiclean-fuel-fired gas turbine/steam (General Electric)	547	.574	1.7	.06	7.95	1.58	.295	.09	0	0
10 - Coal/MHD/steam (General Electric)	1932	.5	.3	.1	5.1	84	.33	.10	^d .0012	.079
11 - Low-Btu gasifier/molten-carbonate fuel cell/steam (United Technologies Corp.)	635	.74	.03	.09	20	^e	.40	.18	0	.085

^dSeed makeup.^eWaste disposal land requirements included in total powerplant land needs.

5.1.1 Performance

The efficiency results for all the systems studied in Phase 2 are plotted in figure 5. The systems are identified by the numbers listed in table V; these system numbers will be used throughout this section to identify the systems. The systems are arranged in order of the peak cycle temperature of the working fluid, except for the low-Btu gasifier/molten-carbonate fuel cell/steam system (system 11). The fuel cell/steam system is listed last to emphasize that it is only partially a heat engine. The pressurized-fluidized-bed (PFB) cases are listed according to the temperature of the primary power cycle, not that of the furnace-pressurizing cycle.

All three efficiencies defined in the ECAS ground rules (section 3.2) are listed in the figure. The general trend of thermodynamic efficiency is to increase with increasing peak temperature. However, the variation in powerplant and overall efficiencies with temperature is not as consistent. This is because of differences among the systems in such things as energy loss in fuel processing, auxiliary power requirements, furnace system performance, and gasifier/cleanup system performance. In reference 7, energy flow diagrams are presented for each system to illustrate both the subsystem efficiencies and the manner in which the subsystems are interfaced. The efficiencies shown in figure 5 and how they compare are explained there by using these energy flow diagrams and by mathematically expressing the overall energy efficiencies in terms of the subsystem efficiencies in each case.

Examining the overall efficiency of each system in terms of its subsystems shows that in most cases much of the reduction in performance from the thermodynamic efficiency follows from using coal as the fuel and/or from the requirement that the specified environmental con-

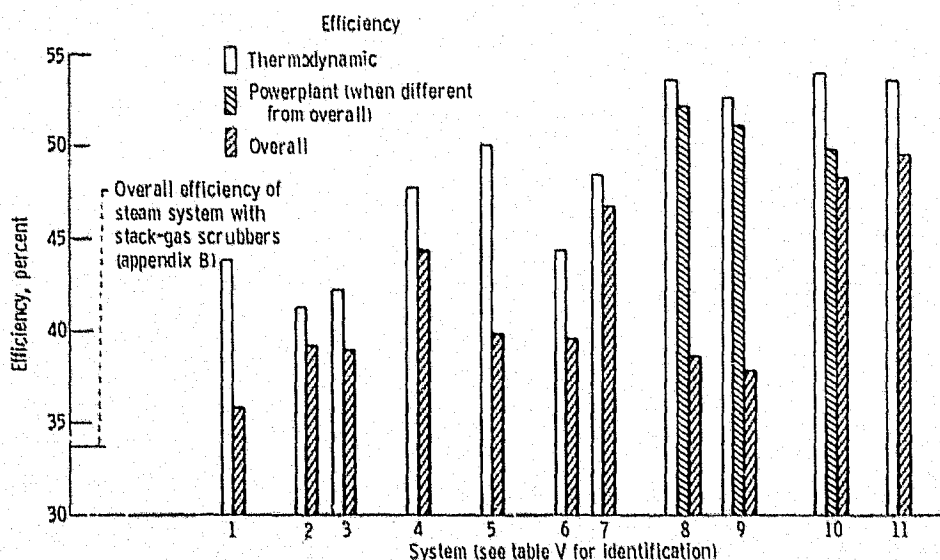


Figure 5. - ECAS Phase 2 efficiency results.

straints be met. For the open-cycle systems (6 to 11) this performance loss appears, in part, either in the form of the gasifier/cleanup system losses (systems 6, 7, and 11); in terms of off-site fuel-processing losses (systems 8 and 9); or, in the case of the open-cycle MHD/steam system (10), in terms of the seed-reprocessing (sulfur removal) losses. For the closed-cycle systems, this performance penalty appears in the form of losses from the furnace subsystem, which is required to combust the coal in an environmentally acceptable manner and to transfer the heat to the primary power system. In all but two cases (i.e., in all but the H-coal cases, systems 8 and 9), this penalty is also reflected in the auxiliary power requirements for coal preparation and for solid waste handling.

For the closed-cycle systems with atmospheric combustion (systems 1 and 5 in fig. 5), furnace system losses (including the sensible and latent heat in the stack gases as well as the heat and combustion losses from the furnace) reduce the powerplant efficiency 10 to 20 percent below the primary-cycle thermodynamic efficiency. For the closed-cycle systems with pressurized combustion (systems 2 to 4), however, furnace losses have less of an effect on the overall efficiency. These systems are, in effect, a closed primary cycle operating in parallel with a gas turbine/steam system. The furnace-pressurizing turbomachinery produces useful power, and the remaining useful energy in the turbine exhaust is input to the steam-cycle feedwater of the primary cycle. In this way the furnace system, in addition to providing the heat input to the primary cycle, produces useful power in parallel with the primary cycle. The effective efficiency of the power produced by the furnace cycle is of the order of 40 percent for the ECAS cases. The overall efficiency of these cases is a weighted average of this furnace-cycle efficiency and the primary-cycle thermodynamic efficiency. And it is higher than the overall efficiency of the corresponding system with an atmospheric furnace, even though the furnace and stack-gas losses are comparable.

As shown in figure 5, the overall efficiencies of the 11 systems studied in ECAS all exceed that predicted for a steam system with wet-limestone stack-gas scrubbers. As described in appendix B the overall efficiency is slightly lower for this steam system than for the AFB/steam system because of steam extraction for stack-gas reheating after scrubbing and slightly higher auxiliary power requirements.

5.1.2 Capital Cost

To permit cost comparisons on a consistent basis, all the materials and labor cost estimates made by the contractors have been arranged into six cost categories. These cost categories and the elements within each major cost category are as follows:

1.0 - Land improvements and structures:

- Site preparation

- Site utilities

Roadways and tracks

Earth work

Concrete foundations

Superstructures and enclosures

Cranes

Water treatment ponds

Laboratory, machine shop, and office equipment

2.0 - Furnace (or gasifier) and solids handling:

Furnace modules (AFB, PFB) or gasifier

Furnace auxiliaries

Exhaust or fuel gas cleanup equipment

Air supply equipment

Coal, dolomite/limestone, and spent solids handling

Gas turbine-compressor-generator

Heaters, economizers, and tanks

Stacks and accessories

Draft ducts and gas piping

3.0 - Topping-cycle equipment:

Turbine-generator, MHD, and fuel cells

Heaters, exchangers, tanks, and vessels

Pumps and compressors

Recuperator, precooler, and condenser

Piping and piping insulation

Safety equipment

Stacks

Potassium condenser - steam boiler

4.0 - Bottoming cycle:

Steam or organic turbine-generator

Steam or organic boiler

Feedwater pumps and others

Condenser

Piping and piping insulation

5.0 - Electrical plant and instrumentation:

Transformers

Main bus

Switch gear and control centers

Auxiliary diesel generators

- Conduit, cable, trays, and wire
- Instrumentation and controls
- 6.0 - Cooling tower system:
 - Cooling towers
 - Main circulating-water pumps
 - Basin and circulating-water system

The cost estimates arranged into these categories are shown in figure 6. The costs shown are the sum of all components and other materials and labor required. The indirect site labor charges are included; but the architect and engineering (A&E) services, contingency, interest, and escalation are not.

Categories 2.0, 3.0, and 4.0 (i.e., the furnace, gasifier, and/or fuel-handling category and the topping- and bottoming-cycle categories) represent the principal parts of the overall system. As shown in the figure, these categories account for the major part of the total material and labor costs and understandably show the most variation from one system to another.

The furnace subsystem costs (category 2.0) are a significant contribution to the total system cost for all the closed-cycle systems (systems 1 to 5) in Phase 2. As discussed in section 5.2.1 the cost estimates for the pressurized-fluidized-bed furnace module for the steam system (systems 2 and 3) are lower than that for the atmospheric-fluidized-bed module for the steam system (system 1). But the additional cost for pressurizing turbomachinery and its associated gas cleaning (particulate removal) equipment and for more expensive solids injection equipment results in a higher furnace subsystem cost, as shown in figure 6.

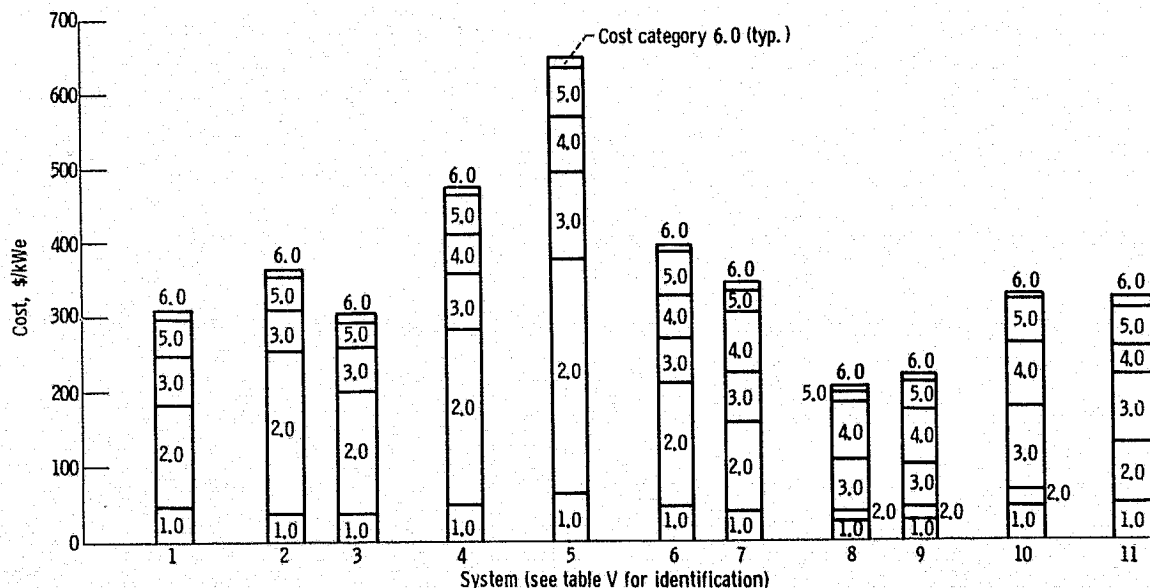


Figure 6. - Comparison of material and labor estimates for ECAS Phase 2 systems by cost category.

The closed-cycle gas turbine/organic system (system 5) and the potassium/steam system (system 4) show the highest capital costs. These are the two closed-cycle systems included in Phase 2 that use higher peak temperatures than the steam systems. As shown in figure 5 they have higher overall efficiency; but the higher costs, particularly in category 2.0 (the furnace subsystem) resulted in higher COE. This reveals the strong influence of the peak cycle temperature on furnace heat-exchanger cost and, hence, on system competitiveness.

Open-cycle systems have the potential for lower capital cost because of the absence of an expensive furnace subsystem. They also have the potential for competitive (or higher) powerplant efficiencies than closed-cycle systems because they are able to operate at higher working-fluid temperatures and because they are not subject to the additional losses of a closed-cycle furnace subsystem. This is illustrated by comparing the semiclean-fuel (H-coal)-fired gas turbine/steam combined cycle (systems 8 and 9) with the AFB/steam system (system 1). The powerplant efficiencies for the two combined-cycle systems, shown in figure 5, are more than 10 percentage points higher than that of the steam system; and their capital costs, shown in figure 6, in \$/kWe are more than 30 percent lower. However, for the ECAS ground rules, these potential advantages of open-cycle systems are not fully realized. Since coal is the specified fuel and since most open-cycle systems are intolerant of contaminants in the combustion gas, the fuel forms actually used in those systems are preprocessed. In the H-coal-fired cases, this lowers the overall energy efficiency (coal pile to bus bar) to about the same level as that of the steam systems because of the coal-to-H-coal fuel conversion efficiency. Also the influence of the lower capital cost of the combined-cycle gas turbine/steam turbine system on the COE is partly offset by the higher price of H-coal as compared with coal.

The other option that was considered for open-cycle systems (systems 6, 7, and 11) is the use of an integrated coal gasifier. As the results in figure 5 reveal, using an integrated gasifier yields higher overall energy efficiency, but the capital cost of the gasifier/cleanup system is in the same range as the cost of the furnace system required for the closed cycles (category 2.0 in fig. 6).

It has been assumed that the open-cycle MHD/steam system is more tolerant of coal contaminants, especially ash. Therefore, no preprocessing of the coal, other than crushing and drying, was specified. Also, the system does not require a fuel more expensive than coal, except for a small amount of intermediate-Btu fuel used in seed reprocessing. However, primarily because of the higher temperatures and the direct use of coal, the total capital cost of the rest of the system (categories 3.0 and 4.0) is high enough to compensate, so that the overall capital cost in \$/kWe was estimated to be in the same range as for the steam systems.

The total capital cost estimates for all the systems, showing the contributions of A&E services, contingency, and interest and escalation during construction, are shown in figure 7. The procedures used to estimate these additional costs are discussed in sections 3.3 and 3.7.

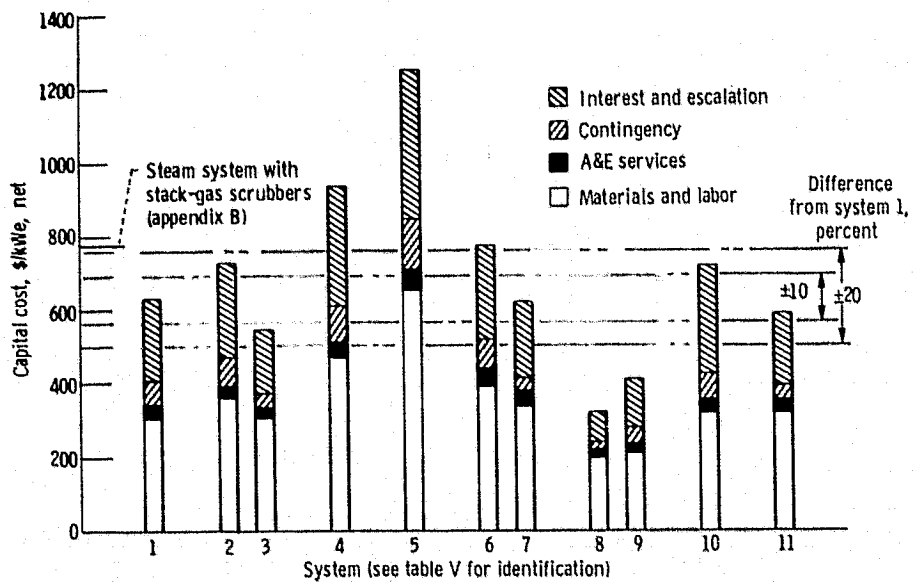


Figure 7. - ECAS Phase 2 capital cost estimates.

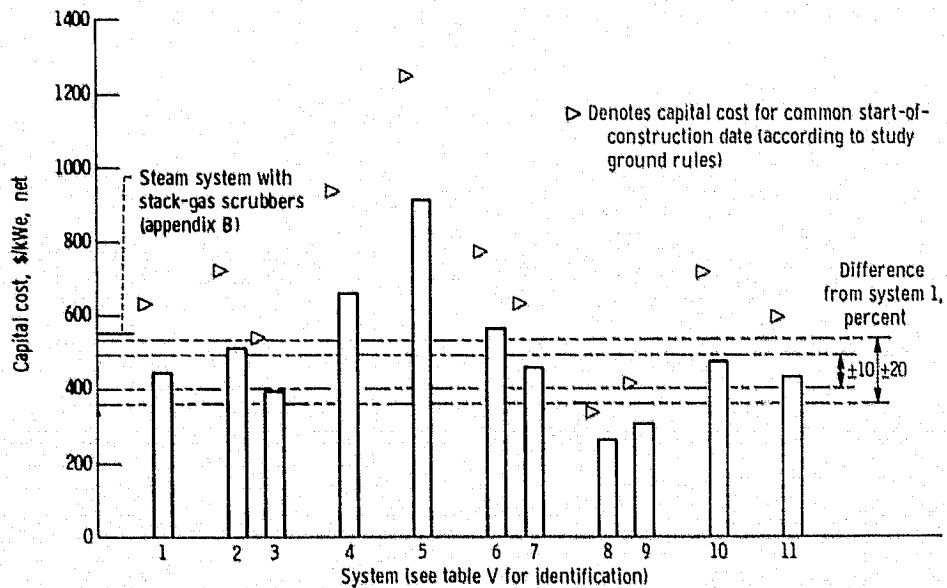


Figure 8. - Comparison of capital cost estimates in constant mid-1975 dollars for ECAS Phase 2 systems.

Except for four systems, the total capital cost estimates shown in figure 7 are within about 20 percent of the AFB/steam system cost. The two semiclean-fuel (H-coal)-fired gas turbine/steam turbine systems are lower than this range, and the AFB/closed-cycle gas turbine/organic and PFB/potassium/steam systems are higher - as discussed previously. As indicated on the ordinate, the capital cost estimate for a steam system with wet-lime stack-gas scrubbers (the case with 175⁰ F stack-gas temperature described in appendix B) is about 20 percent above that for the AFB/steam system. As shown, the charges added to the material and labor cost estimates (i.e., A&E services, contingency, and interest and escalation during construction) roughly double the cost above the material and labor subtotal in all cases. The total capital costs in constant mid-1975 dollars, as listed in table V, are shown in figure 8.

5.1.3 Cost of Electricity and Overall Efficiency.

The COE results and the overall efficiencies for all the systems are plotted in figure 9. As shown, the low-Btu gasifier/molten-carbonate fuel cell/steam system, the coal/open-cycle MHD/steam system, and the low-Btu gasifier/gas turbine/steam combined-cycle system as studied by Westinghouse are grouped together. They have efficiencies in the high-40-percent range and COE's competitive with the advanced steam systems. The gas turbine/steam combined-cycle system with the integrated gasifier as studied by G.E. (which uses a nearer term gasification system) has lower efficiency and higher COE (section 5.2.2). The two gas turbine/steam combined-cycle systems fired by H-coal have COE's competitive with those of the advanced steam systems and overall efficiencies in the high-30-percent range. As shown in table V and figure 5, the powerplant efficiencies of these two cases exceed 50 percent, but their overall efficiencies are considerably lower because of the 74 percent coal-to-semiclean-fuel conversion efficiency. The two PFB/steam systems have efficiencies near 40 percent and show a significant difference in estimated COE. As discussed in section 5.2.1 this is partly due to differences in cost estimates in the PFB-subsystem cost category and partly due to differences in A&E services, contingency, interest, and escalation. The COE's for the PFB/potassium/steam system and the AFB/closed-cycle gas turbine/organic system are significantly higher than those for the steam systems primarily because of the higher capital cost associated with the furnace-subsystem and primary-cycle cost categories. The results for the steam system with stack-gas scrubber are also shown in figure 9. As discussed in appendix B, steam extracted from the turbine is used to reheat the stack gases after scrubbing. This steam extraction reduces the power output and hence the efficiency. As shown, reheating the stack gases to 250⁰ F, which requires more steam extraction than the 175⁰ F case, results in significantly lower efficiency and higher COE.

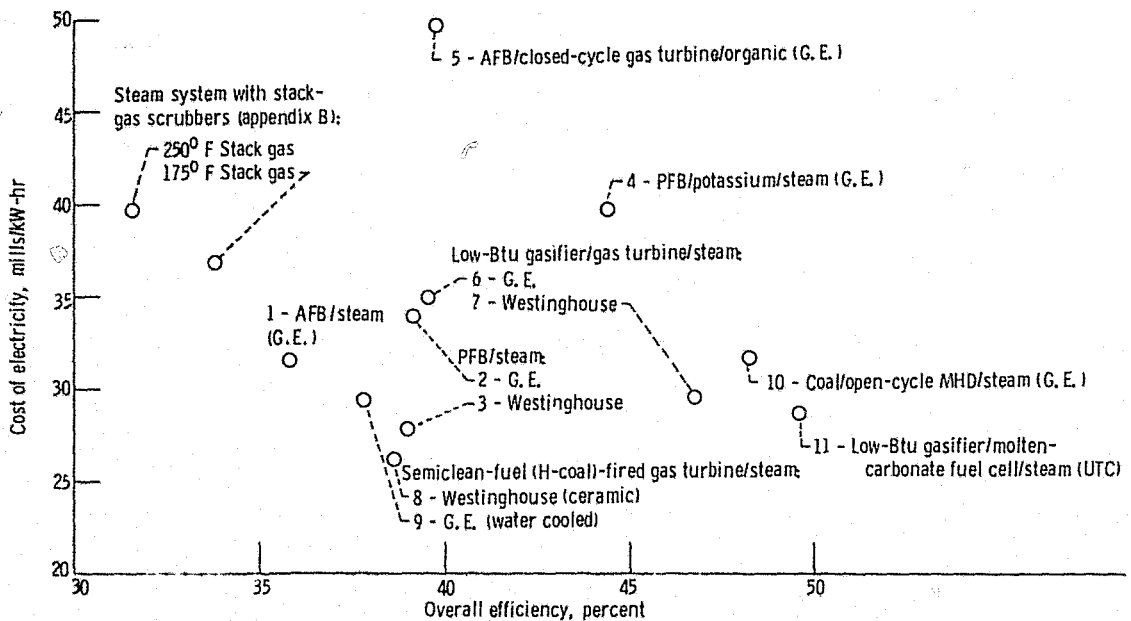
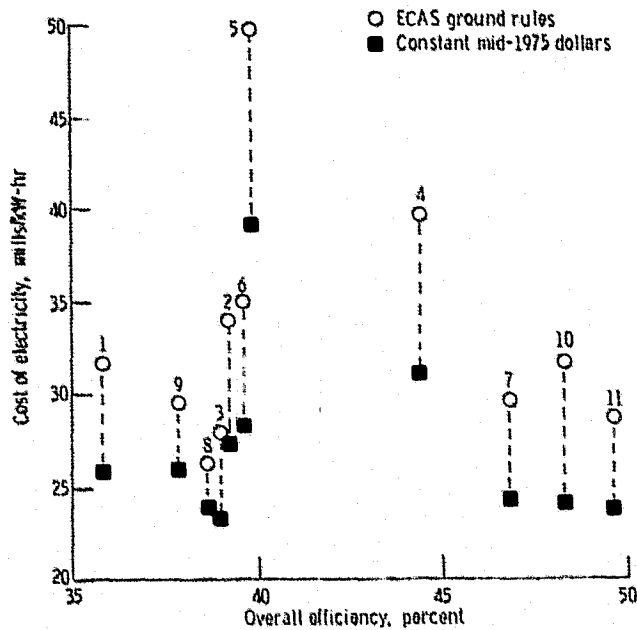


Figure 9. - ECAS Phase 2 results using ECAS ground rules.

In comparing the results in figure 9, it should be remembered that they assume that each powerplant has reached a state of commercial maturity. The R&D plans and implementation assessment deal with the time, cost, and other issues involved in reaching this state. The influence of capital cost uncertainties that follow from differences in the current level of technology is described in section 5.4.

The COE can be calculated from the estimated capital cost and efficiency of a system according to many different ground rules. The results for all systems have been published by the contractors in sufficient detail to allow the recalculation of COE according to ground rules other than those specified for ECAS. To determine whether the selection of ground rules affected the relative comparison of the COE's of these Phase 2 cases, the COE for each was recalculated for several variations in the ground rules. The COE calculated from the capital cost in constant mid-1975 dollars (as defined in section 5.1) is shown in figure 10 and table V.

Another variation in ground rules examined was the influence of changes in fuel price. Increasing fuel prices would make the higher efficiency systems appear relatively more favorable. In figure 11, the COE's averaged over 30 years (assumed powerplant lifetime) and expressed in terms of mid-1975 dollars are shown for all the ECAS Phase 2 systems. An inflation rate of 3.25 percent per year was assumed as an example (i.e., half of the specified escalation rate for capital during powerplant construction). The average COE is defined here as the total bus-bar cost of producing electricity for some time period divided by the total power produced in that period. This is calculated by assuming that the capacity factor does



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Figure 10. - ECAS Phase 2 results with change in ground rules to express cost in mid-1975 dollars.

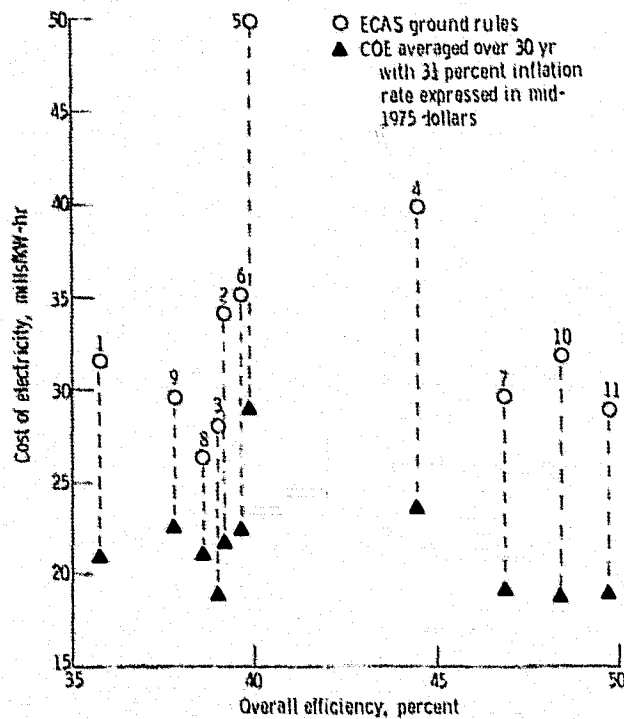


Figure 11. - ECAS Phase 2 results with change in ground rules to express cost of electricity averaged over powerplant lifetime.

not change. When the average is expressed in terms of mid-1975 dollars, the COE's are lower than those shown in figures 9 and 10. If the fuel and O&M costs increase at the general inflation rate as assumed, their contributions to COE do not change from year to year when expressed in terms of a constant-year dollar (mid-1975 in this case). But the capital cost contribution to COE, when expressed in mid-1975 dollars, would decrease in future years because of the increasing relative purchasing power of mid-1975 dollars as compared with the current-year dollars in which it is actually paid. As shown, the relative competitive positions of the systems are not, for practical purposes, significantly changed. Note that after 30 years of escalation at 3.25 percent, the fuel cost is increased by a factor of 2.6.

5.1.4 Emissions and Natural Resources

The nitrogen oxides and sulfur dioxide emissions estimates are shown for each powerplant in figure 12. The water requirements and total solid wastes are shown in figures 13 and 14. These results are also listed in table V(b).

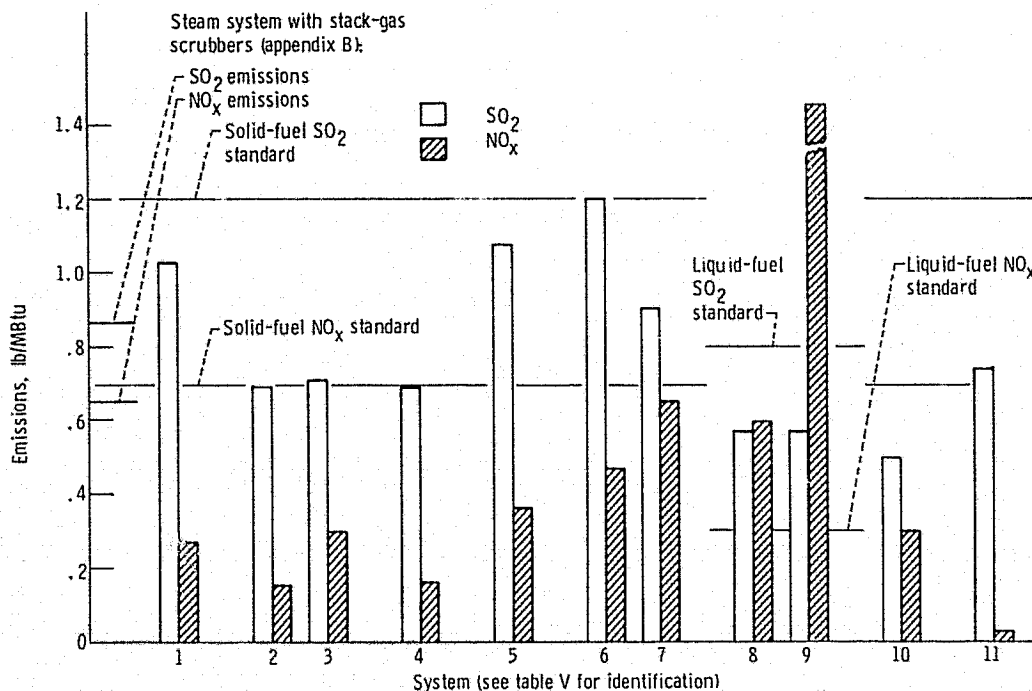


Figure 12. - Sulfur dioxide and nitrogen oxides emissions estimates (Phase 2).

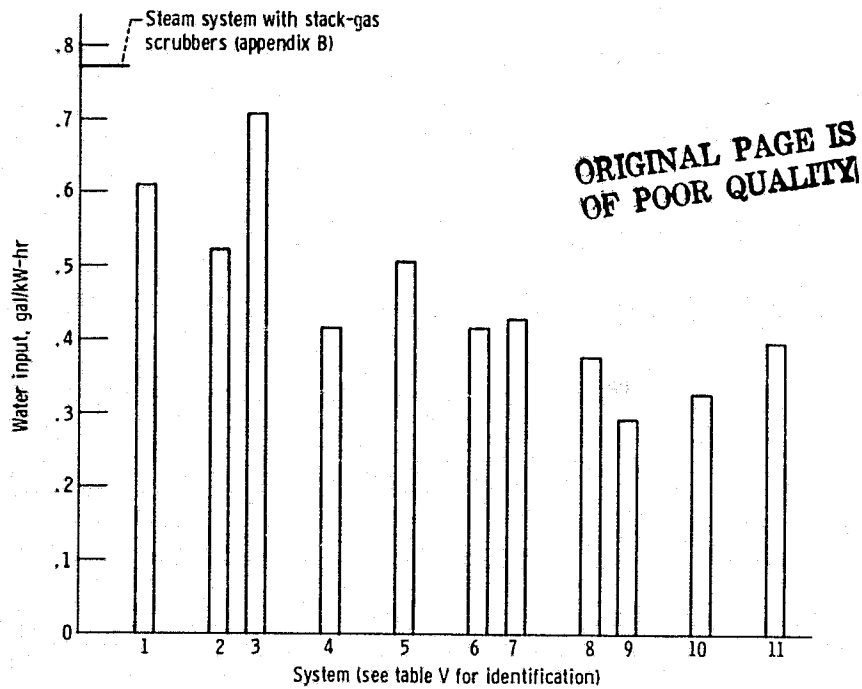


Figure 13. - Water requirements (Phase 2).

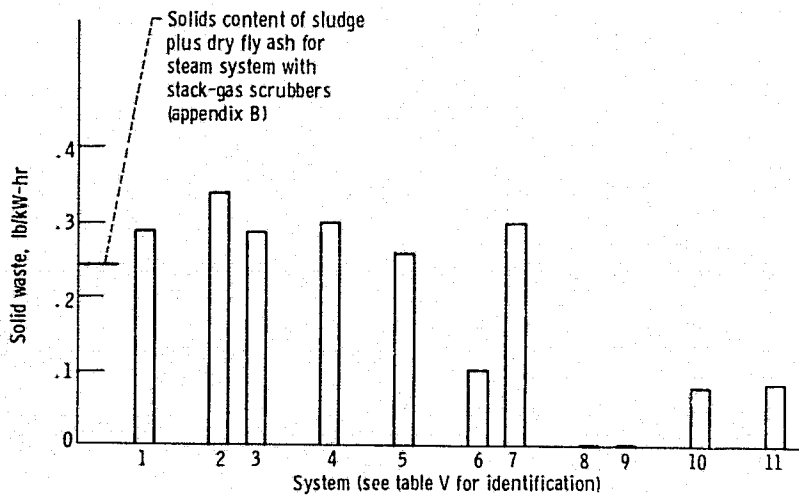


Figure 14. - Solid wastes (Phase 2).

In general the parameters and configurations of each conceptual design were chosen in part to meet the emissions standards specified for the study (section 3.5). The two semiclean-fuel-fired gas turbine/steam systems, however, did not meet the nitrogen oxide standards as discussed in section 5.2.2. The flexibility of each type of system to meet more stringent emissions standards is a consideration of the implementation assessment. This and the natural resource requirements are discussed in section 5.4.

5.2 CONCEPTUAL DESIGN RESULTS BY SYSTEM

In this section the cost and performance results for each conceptual design are summarized and discussed on a system-by-system basis. Where appropriate the results of different contractors for similar systems are compared to identify and explain differences in approaches and/or results. In some cases, additional calculations based on a contractor's results were done at NASA in order to give insight into the results or to evaluate possible changes or improvements to the configurations studied. These are included where appropriate. Unless otherwise noted, the COE results quoted are according to ECAS ground rules.

5.2.1 Advanced Steam Systems

The two steam systems studied in Phase 2 of ECAS are conventional 3500-psig/1000° F/1000° F steam cycles with advanced fluidized-bed furnaces. Limestone or dolomite is injected into the fluidized beds to capture the sulfur during coal combustion. Both General Electric and Westinghouse studied a steam system with pressurized-fluidized-bed (PFB) furnaces operating at 10 atmospheres. And G.E. also studied a steam system with an atmospheric-fluidized-bed (AFB) furnace. Simplified schematic diagrams of the AFB/steam and PFB/steam systems are given in figures 15 and 16, respectively.

In the PFB/steam system, the electric power is generated by both the steam cycle and the PFB-pressurizing gas turbine operating in parallel. The air for the PFB furnace subsystem is supplied by a turbine-driven compressor. The combustion gases leave the PFB furnace at nearly bed temperature and are expanded in the gas turbine. Particulates are removed from the gas, before it reaches the turbine inlet, by cyclones and granular bed filters. The gas-turbine exhaust is cooled to the stack temperature by transferring heat to the steam-cycle feedwater.

In the AFB/steam system, the only function of the furnace subsystem is to supply heat, in an environmentally acceptable manner, to the steam cycle. All system electric power is generated by the steam-cycle subsystem, and the air for combustion and bed fluidization is supplied by electric-motor-driven fans. The combustion gases are cooled in the convection space above the bed and leave the AFB furnace at 730° F. Particulates are then removed by

cyclones and electrostatic precipitators. The gas is reduced in temperature to the stack inlet conditions by preheating the combustion air.

The overall efficiencies of the two PFB/steam systems are 39.2 percent for the G.E. system and 39.0 percent for the Westinghouse system. The costs of electricity of the two PFB/steam systems, however, show a more substantial difference (34.1 mills/kW-hr for the G.E. system and 28.1 mills/kW-hr for the Westinghouse system). The 6-mill/kW-hr difference between the two COE's is mainly due to the difference of 5.6 mills/kW-hr in the capital contribution. The difference in the estimated capital costs is due in part to the different material and labor costs estimated by the two contractors and in part to different factors for architect and engineering services, contingency, and (because of a difference in estimated construction time) interest and escalation.

The major contributors to the differences in material and labor costs are differences in the hot-gas cleanup and solids-injection subsystems. The substantial cost differences in these two subsystems are due to the use of widely different design parameters, approaches, and requirements, all of which need further experimental verification. The hot-gas cleanup subsystem (cyclones and granular bed filters) shows the greatest cost difference among the subsystems of the PFB/steam system. This subsystem must remove solid particles to a level that is compatible with the pressurizing gas turbines operating near bed temperature. However, the

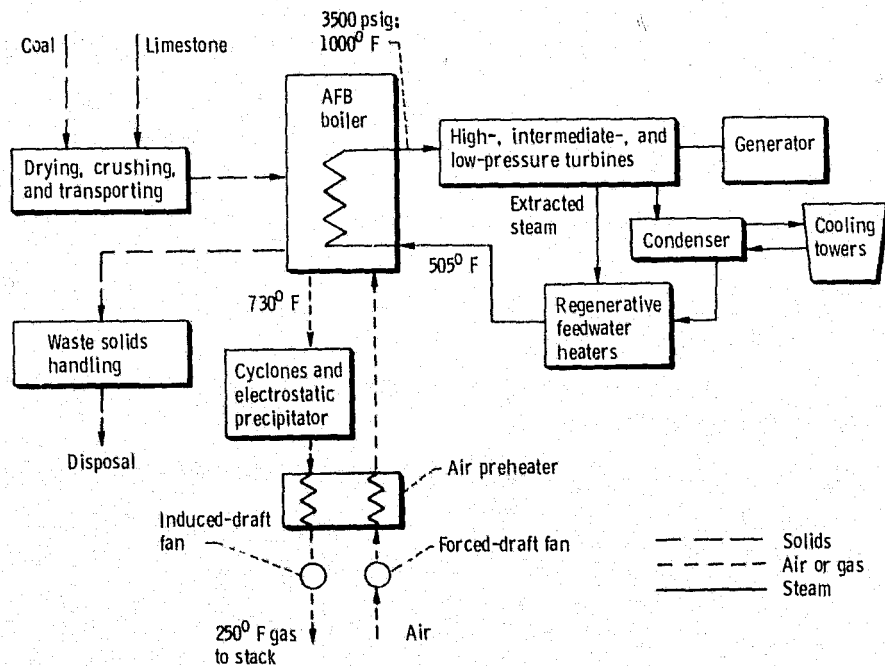


Figure 15. - Simplified schematic diagram of AFB/steam system.

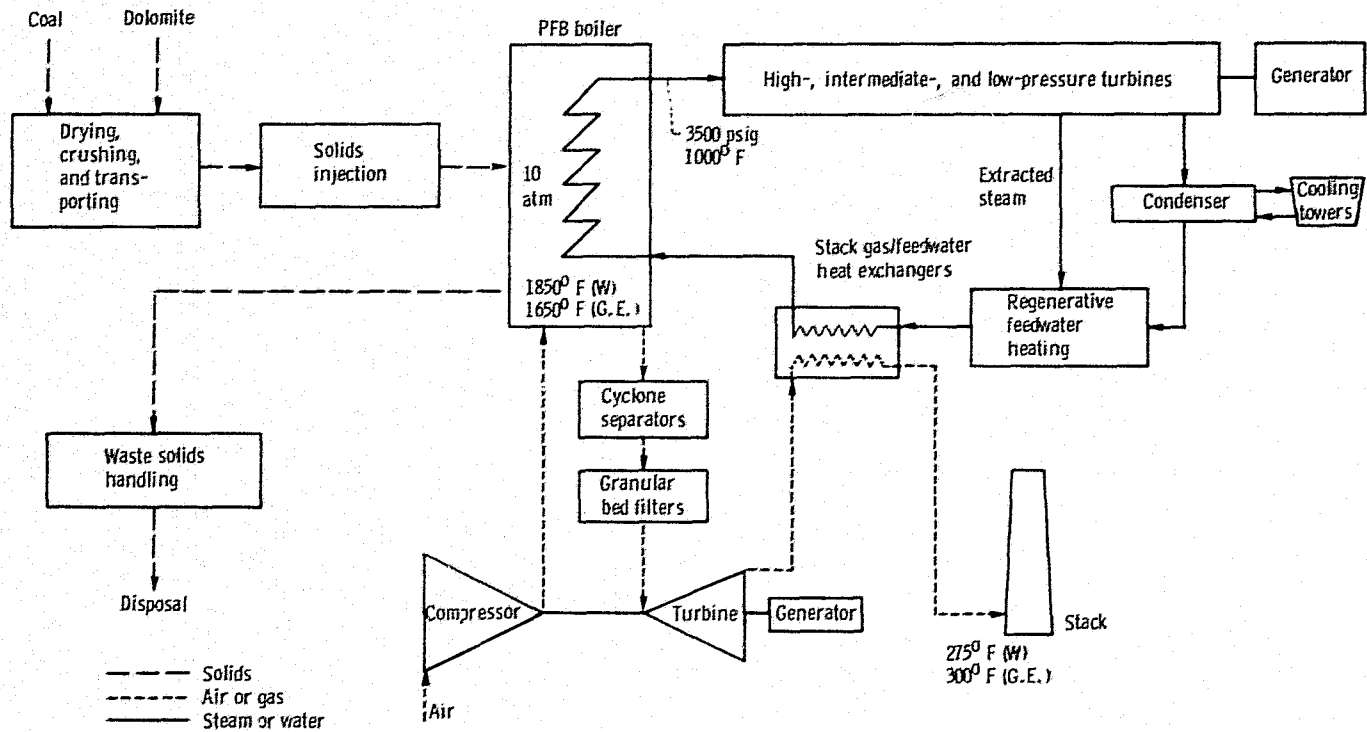


Figure 16. - Simplified schematic diagram of PFB/steam system.

cleanup requirements are uncertain because the estimated particulate loading and predicted particle size distribution of the combustion gas are based on estimated bed elutriation characteristics and because the hot-corrosion and erosion effects on the pressurizing gas turbines operating near bed temperatures are not well known. Resolution of these cost differences must await experimental verification of the cleanup technology and demonstration at actual operating conditions.

The AFB/steam and PFB/steam systems studied by G.E. have overall efficiencies of 35.8 and 39.2 percent, respectively. In the PFB/steam system and the furnace-pressurizing turbomachinery generates electric power in parallel with the steam cycle. The available heat in the turbine exhaust above the 300^o F stack temperature is recovered by the steam-cycle feedwater, resulting in the high effective efficiency of the PFB-pressurizing cycle. Also, the auxiliary power requirements for the AFB/steam system are higher since the air for combustion and bed fluidization is supplied by motor-driven fans.

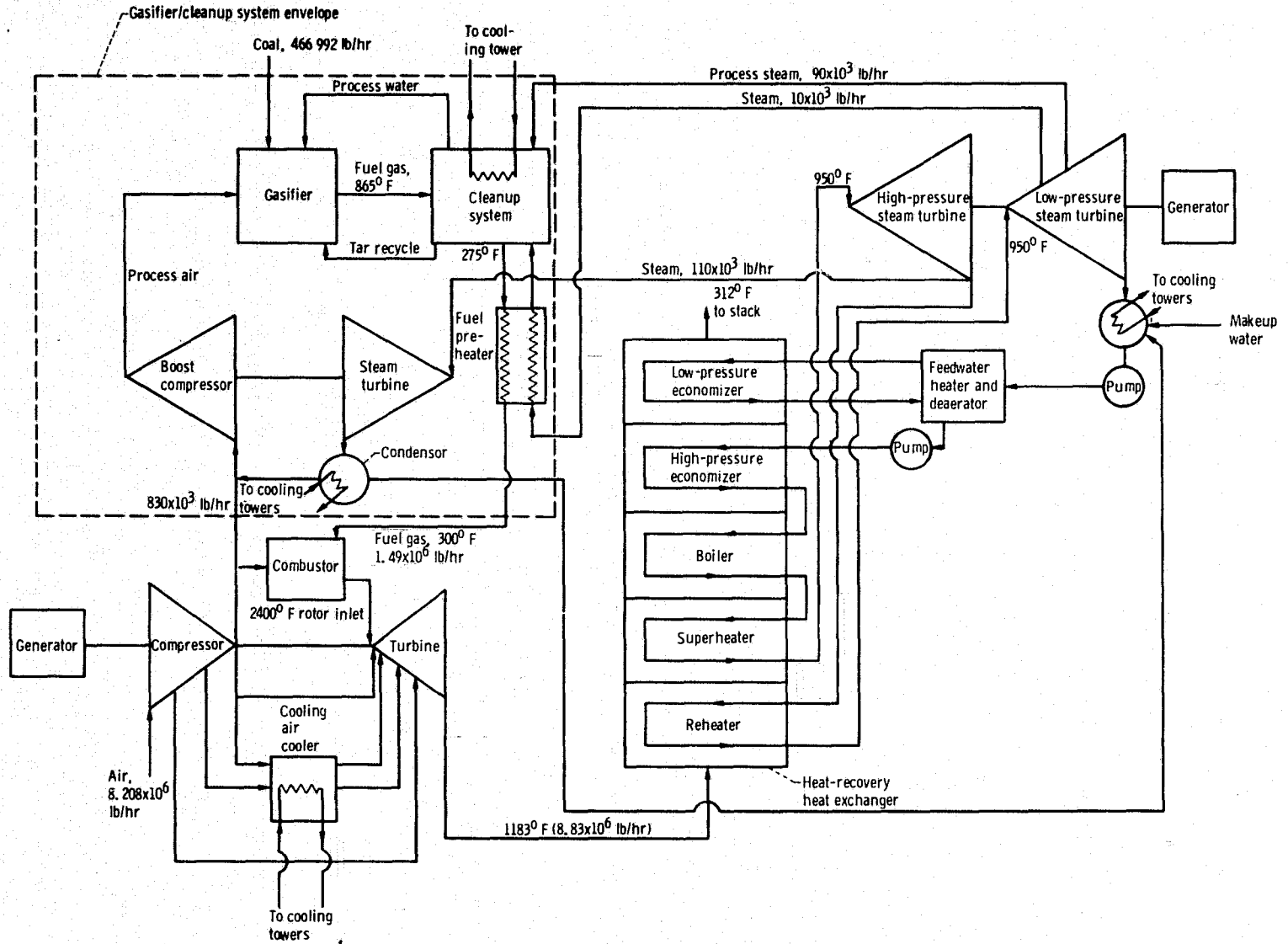
The COE of the AFB/steam system studied by G.E. is 31.7 mills/kW-hr, 2.4 mills/kW-hr less than the COE of the PFB/steam system also studied by G.E. The fuel contribution to the COE is lower in the PFB/steam system because of its higher overall efficiency. But the capital contribution to the COE is substantially higher in the PFB/steam system and outweighs the lower fuel contribution. The capital cost differences are primarily due to differences in the cost estimates of the furnace subsystems. Although the cost estimate for the PFB module is lower than that for the AFB module, the additional costs of the pressurizing turbomachinery and the higher cost estimates for the solids-injection systems and for the hot-gas particulate removal systems result in a higher total cost for the PFB furnace system.

As discussed, there are uncertainties associated with the solids-injection and hot-gas cleanup systems for the PFB. Therefore, the relative cost of a PFB/steam system as compared with an AFB/steam system is uncertain at this time, and it will remain so until the technology for these subsystems is more fully developed.

5.2.2 Combined-Cycle Gas Turbine/Steam Turbine Systems

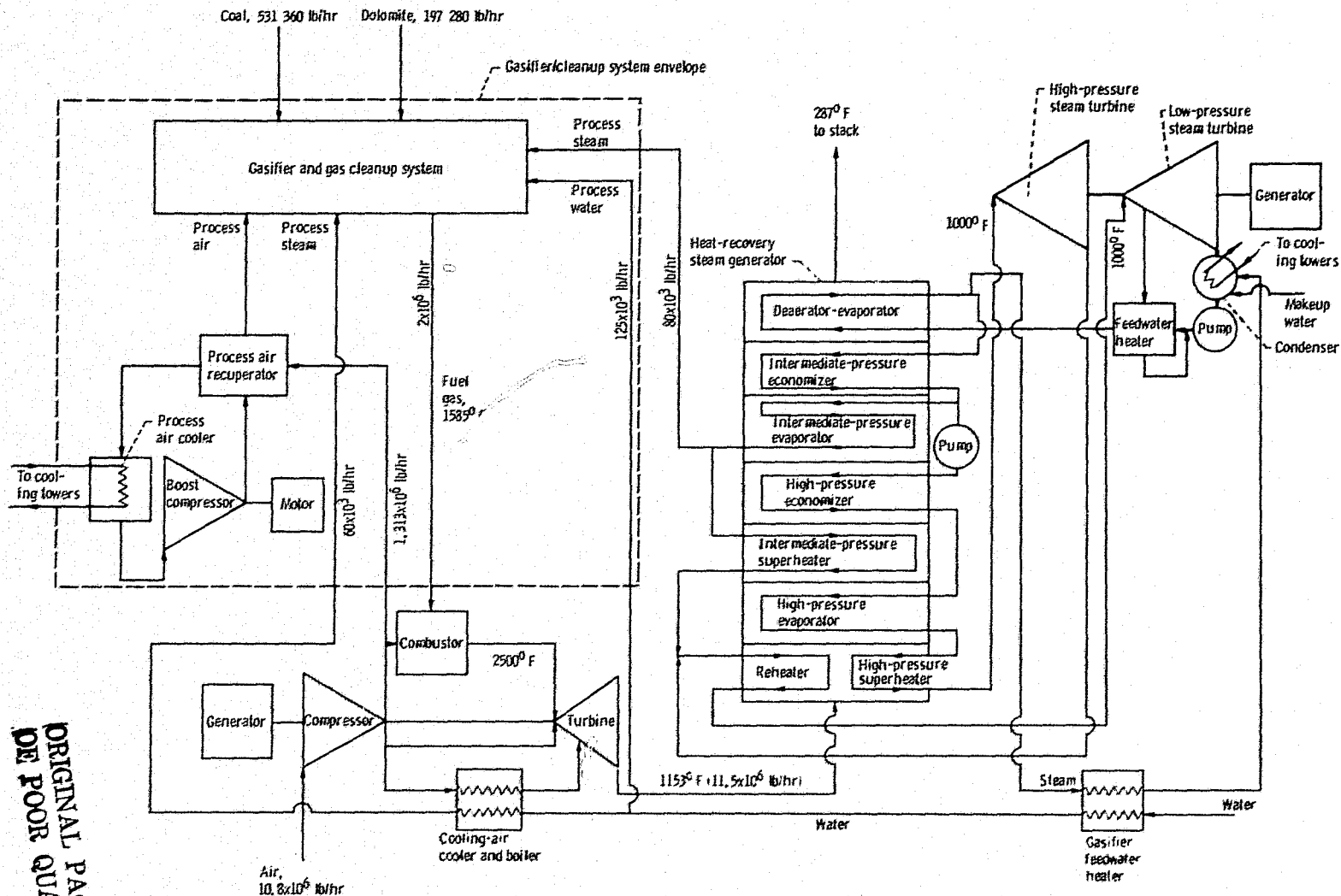
Four combined-cycle gas turbine/steam turbine conceptual designs were included in Phase 2. General Electric and Westinghouse each considered both a system with an integrated low-Btu gasifier and a system fired by an over-the-fence semiclean fuel derived from coal in the H-coal process.

5.2.2.1 Systems with integrated gasifiers. - The G.E. integrated-gasifier case employed air-cooled gas turbines with a turbine inlet temperature (defined by G.E. as the temperature at the inlet to the first-stage rotor) of 2400^o F and bottomed by an 1800-psig/950^o F/950^o F steam powerplant. This schematic diagram is shown in figure 17(a). This powerplant was integrated with a G.E. advanced fixed-bed gasifier and a cold-gas cleanup



(a) General Electric. (All flow rates are for total of four gas turbines.)

Figure 17. - Schematic diagram for low-Btu gasifier/gas turbine/steam combined-cycle system.



(b) Westinghouse. (All flow rates are for total of four gas turbines.)

Figure 17. - Concluded.

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system consisting of a water wash (to remove coal tar) and Alkazid and Claus plants for the removal and recovery of sulfur. This design resulted in an overall efficiency of 39.6 percent, a capital cost of \$771/kWe, and a COE of 35.1 mills/kW-hr.

The Westinghouse integrated-gasifier case used air-cooled turbines at 2500° F (defined by Westinghouse as the temperature at the inlet to the first-stage stator) and bottomed by a 2400-psig/1000° F/1000° F steam powerplant. The schematic diagram is shown in figure 17(b). The steam cycle included a single steam induction to improve the steam-cycle efficiency and the thermodynamic fit between the gas turbine and the steam cycle. This system was integrated with a Westinghouse fluidized-bed gasifier with in-bed desulfurization and hot-gas particulate removal. This system had an overall efficiency of 46.8 percent, with a capital cost of \$614/kWe and a COE of 29.1 mills/kW-hr.

Several additional configurations were analyzed at NASA by modifying the contractors' results. Two of these consisted of removing the gasifier while keeping the other system parameters the same, in order to show the influence of the gasifier/cleanup system, as well as the method of integration, on the overall powerplant efficiency and cost. The effective efficiency of the integrated gasifier/cleanup subsystem used by G.E. is lower than that of the subsystem used by Westinghouse. This is mainly due to the use, in the G.E. system, of a cold-gas sulfur removal process preceded by a water wash for tar removal and the consequent loss of much of the sensible heat of the fuel gas.

Of the 7.2-percentage-point difference in efficiency between the contractors' integrated-gasifier combined cycle cases, 4.3 points are due to differences in the gasifier/cleanup systems and the method used to integrate the gasifier with the powerplant. An additional 2.8 points are attributed to the contractors' selections of compressor pressure ratio, their estimated gas turbine cooling requirements, differences in steam-cycle design, and the methods of obtaining gasifier process steam.

The capital cost estimates made by the contractors for their gasifier cases differ by only \$52/kWe before the addition of charges for A&E services, contingency, and interest and escalation and by \$157/kWe if these charges are included. The larger difference in total capital cost is due primarily to the different contingency factors used by the contractors (20 percent for G.E. and 10 percent for Westinghouse) plus the magnification of all differences when applying the escalation and interest rates.

The additional calculations done at NASA included the variations in turbine inlet temperature (2000° to 2500° F) of a combined cycle integrated with an advanced fixed-bed gasifier. With a turbine inlet temperature of 2000° F, in the range of the current state of the art, the overall efficiency is 37 percent and the predicted COE is 37 mills/kW-hr.

Another variation considered at NASA involved the use of the gasifier/cleanup system that was used in the molten-carbonate fuel cell/steam system. The cost estimated for this gasifier/cleanup system (the U-Gas gasifier with iron oxide beds and Allied Chemical plant

sulfur removal and recovery) was lower than the costs estimated for the systems used by G.E. and Westinghouse. The case calculated by NASA integrated this system with a 2500° F combined cycle and resulted in an overall efficiency of 42.2 percent and a COE of 27.8 mills/kW-hr.

The range of estimated COE's and overall efficiencies obtained with the three different gasifier/cleanup systems shows the sensitivity of the overall system to this subsystem. The Phase 2 conceptual designs were done as if these systems had reached a state of commercially mature technology. But the present technological states of these gasifier/cleanup systems differ, and hence the time and money required and the technical issues that must be solved to reach such states of maturity differ. This, in addition to the estimated efficiency and COE, should be considered in comparing these systems.

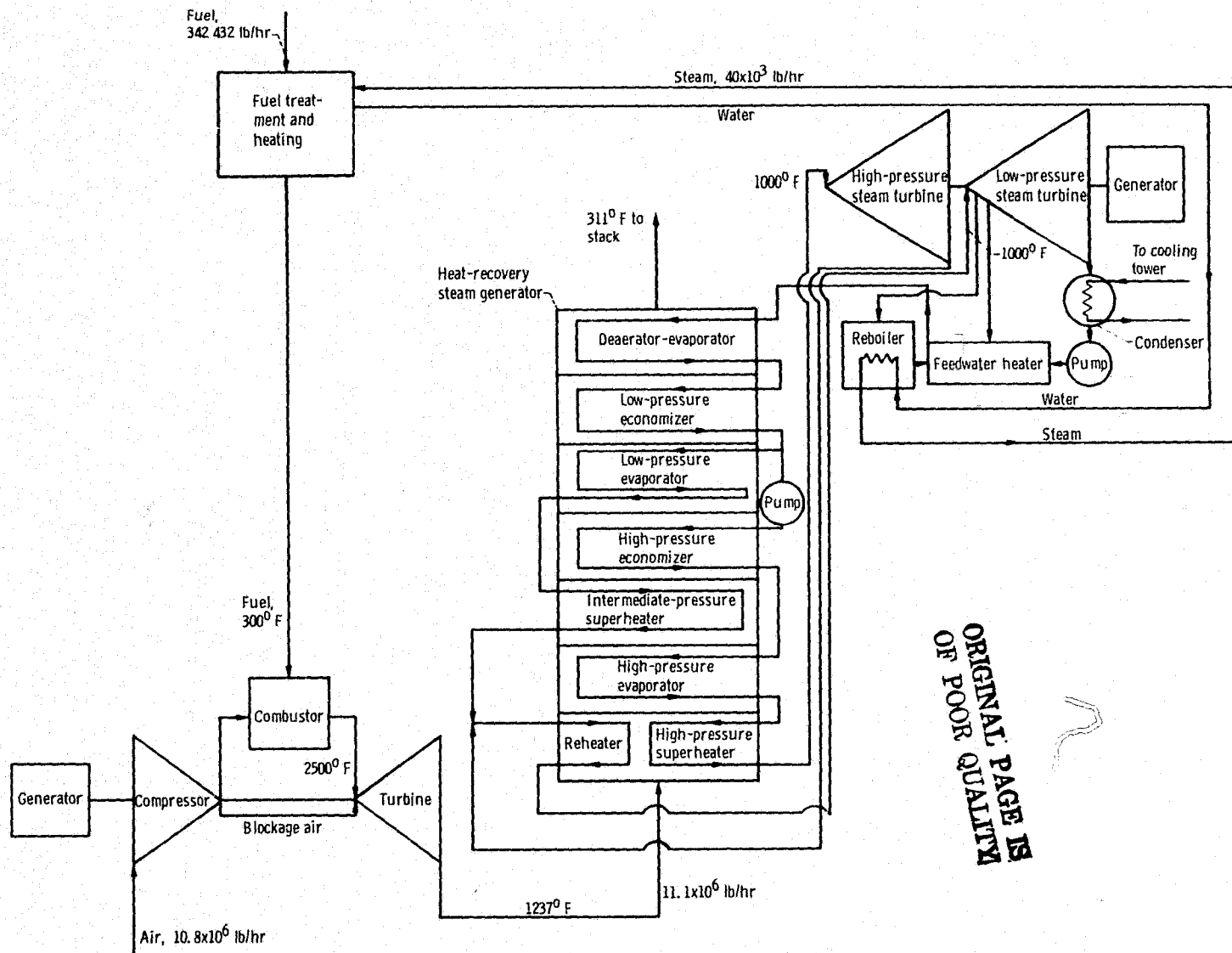
5.2.2.2 Systems fired by semiclean fuel. - The G.E. semiclean-fuel-fired conceptual design consisted of water-cooled gas turbines at a turbine inlet temperature of 3000° F bottomed by a 2400-psig/1000° F/1000° F steam powerplant. The schematic diagram is shown in figure 18(a). Steam is injected into the combustors in an attempt to control thermally formed nitrogen oxides. But because of the high organic nitrogen content in the fuel, this powerplant did not meet the nitrogen oxides emissions standard used for this study. The powerplant efficiency of this design was 51.1 percent. With the specified 74-percent coal-to-fuel-gas conversion efficiency, this results in an overall efficiency (coal pile to bus bar) of 37.8 percent. The capital cost was \$417/kWe, with a COE of 29.5 mills/kW-hr.

The Westinghouse semiclean-fuel-fired case consisted of 2500° F gas turbines with ceramic hot-gas-path parts bottomed by a 2400-psig/1000° F/1000° F steam powerplant also using a single steam induction. The schematic diagram is shown in figure 18(b). An advanced two-stage combustion concept was assumed by Westinghouse in an attempt to control thermal nitrogen oxides and those formed by the fuel-bound nitrogen. This powerplant may also not meet the study emissions standards for nitrogen oxides because of the high nitrogen content of the fuel. The resulting powerplant efficiency was 52.2 percent (38.6 percent coal pile to bus bar). The capital cost estimate is \$328/kWe, with a COE of 26.0 mills/kW-hr.

The Westinghouse semiclean-fuel-fired combined cycle has a 1.1-point higher powerplant efficiency than the G.E. system. The gas-turbine topping cycle efficiencies are very similar, despite the 500° F difference in turbine inlet temperature, since the performance of the G.E. 3000° F water-cooled turbine performance includes losses in cooling the blades but the Westinghouse 2500° F ceramic turbine does not have penalties from these losses.

The lower powerplant efficiency of the G.E. system is primarily the result of a lower steam-cycle performance because of the extraction of steam from the steam turbine for control of nitrogen oxides in the gas turbine combustor. Westinghouse also used a single steam induction, which increases the steam-cycle efficiency; G.E. did not.

Figure 18. - Schematic diagram for semiclean-fuel-fired gas turbine/steam combined-cycle system.



(b) Westinghouse. (All flow rates are for total of four gas turbines.)

Figure 18. - Concluded.

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The capital cost estimate for the Westinghouse case is \$13.5/kWe lower than that for the G.E. case before the added charges are included, and \$88.5/kWe afterwards. The major reason for the larger difference in total cost is again the different factors used by each contractor for contingency (20 percent by G.E. and 7 percent by Westinghouse), plus the difference in the escalation and interest factors resulting from the 5-year construction period estimated by G.E. and the 4-year period estimated by Westinghouse.

Using an over-the-fence fuel rather than an integrated gasifier results in a much lower capital cost system. But when the fuel-processing efficiency is considered, it also results in a lower overall energy efficiency. Using a minimally processed fuel is desirable because it has a lower fuel cost and a higher fuel-conversion efficiency than a clean fuel, but its use increases problems with materials compatibility and fouling of turbine coolant passages in advanced air-cooled turbines. For this reason, Westinghouse considered an all-ceramic turbine (except for an uncooled metallic last stage), and G.E. considered a water-cooled turbine. However, both designs involve major developmental advances. The Westinghouse design includes large rotating ceramic parts. The G.E. design also uses ceramics for the combustor liner, the transition piece, and the first-stage stators; and these will be exposed to local gas temperatures above 3000° F (considering the combustor pattern factor). Also using the semi-clean fuels (and 3000° F turbine inlet temperatures) makes powerplant emissions control a key technical issue. Determining the best trade-off between the degree of off-site fuel processing and the development and use of more-advanced combustors will require considerable experimental and analytical investigation.

5.2.3 Closed-Cycle Gas Turbine/Organic Rankine System

The closed-cycle gas turbine with organic bottoming was investigated by G.E. in Phase 2 of ECAS. A higher turbine inlet temperature (1850° F) than was investigated in Phase 1 was considered in order to explore the system's potential at these higher temperatures. General Electric performed a preliminary parametric evaluation to assist in the selection of system parameters and configuration. This evaluation led to the selection of a helium cycle with a turbine inlet temperature of 1850° F (at the first-stage rotor), a compressor pressure ratio of 3.2, and a recuperator effectiveness of 0.85. This was bottomed with a Fluorinol-85 (FL-85) cycle operating at a maximum temperature and pressure of 440° F and 700 psi, respectively. The schematic diagram of the cycle is shown in figure 19. The heat input to the helium cycle is supplied by a two-stage AFB furnace, as shown in the schematic diagram in figure 20. The two-stage AFB consists of a high-temperature bed (2000° F) and a low-temperature bed (1550° F). The high-temperature bed provides nearly 50 percent of the total heat input to the helium cycle and also serves as the carbon burnup cell. The low-temperature bed supplies the remaining heat input and also captures (in the presence of limestone) approximately 85 per-

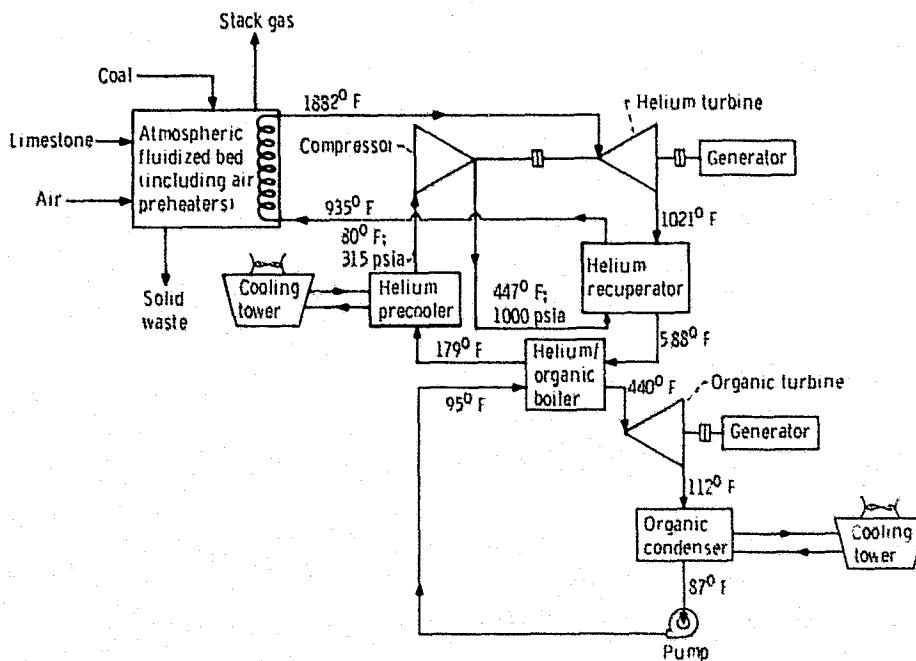


Figure 19. - Schematic diagram of General Electric closed-cycle gas turbine/organic Rankine power system.

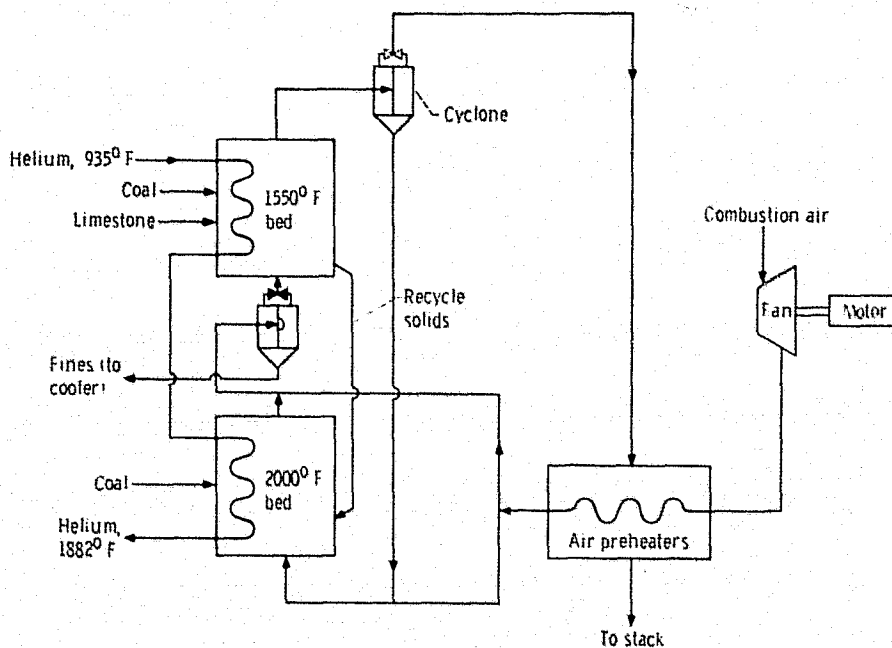


Figure 20. - Schematic diagram of atmospheric fluidized bed for closed-cycle gas turbine.

cent of the sulfur released from the coal burned in both beds. The net power output of this power system is 475.7 MWe. The helium cycle produces 78 percent of the gross power, the remaining 22 percent is supplied by the bottoming cycle. The combined thermodynamic efficiency is 50 percent. The overall efficiency (coal pile to bus bar) is 39.9 percent.

The capital cost of this powerplant was estimated to be \$1232/kWe. By far the largest contribution to the total material and labor cost is made by the AFB furnace and solids-handling subsystem. This subsystem represents nearly 50 percent of the capital cost before charges are added for A&E services, contingency, and interest and escalation during construction. For the ECAS ground rules, the capital contribution to COE is 38.9 mills/kW-hr, the fuel contribution is 8.6 mills/kW-hr, and the operations and maintenance contribution is 1.8 mills/kW-hr - for a total COE of 49.3 mills/kW-hr.

Four additional cases were calculated at NASA. These cases, which were variations of the G.E. Phase 2 results, included both an 1850° F and a 1500° F unbottomed recuperated helium cycle, a 1500° F closed-cycle gas turbine bottomed with an FL-85 cycle, and an 1850° F closed-cycle gas turbine bottomed with an ammonia cycle. These particular cases were selected to show the effect on system performance and cost of (1) a bottoming cycle, (2) the turbine inlet temperature, and (3) the bottoming-cycle working fluid.

Comparing these modified cases with themselves and with the G.E. Phase 2 results reveals that adding a bottoming cycle to either the 1850° F or the 1500° F helium cycle is cost effective. The effective cost of the additional power produced by the bottoming cycles is less than the cost of the power obtained from the unbottomed helium cycles. Also, powerplant capital cost and COE are relatively insensitive to turbine inlet temperature in the range investigated (1500° to 1850° F). This is primarily due to the fact that there is little change (less than 7 percent in the cost per unit of duty of the AFB for a 1500° F helium cycle as compared with the AFB for an 1850° F helium cycle. The specific cost of the 1500° F helium cycle itself is greater than the specific cost of the 1850° F helium cycle because a larger, and therefore more expensive, recuperator is needed. Finally, the additional cases show that changing the bottoming-cycle working fluid does not significantly influence powerplant cost because the bottoming cycle represents a relatively small portion of the total powerplant capital cost.

Comparisons were also made between the NASA-modified case using an unbottomed 1500° F helium cycle with a 1550° AFB and the G.E. advanced steam plant that also used a 1550° F AFB. The helium-cycle cost estimate before added charges is \$422/kWe higher than the steam-plant cost estimate. This large difference is primarily due to the more costly helium heat-exchanger requirements (lower mean temperature difference and higher material temperature) in the helium AFB and to the fact that the helium cycle has the additional cost of an expensive recuperator that has no counterpart in the steam plant.

Parametric performance calculations were also done at NASA to examine the effects of

turbine cooling, working-fluid selection, and compressor intercooling on helium-cycle performance. Also examined was the bottoming-cycle fluid selection and the matching of the bottoming and topping cycles to achieve maximum combined-cycle efficiency. The following observations were made:

(1) As the turbine inlet temperature is increased above 1500°F , turbine cooling requirements predicted for a helium turbine become a significant penalty on cycle performance so that only modest improvements are obtained.

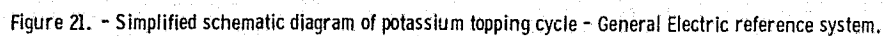
(2) Using a closed-cycle working fluid with a higher molecular weight than helium (such as helium plus argon) would reduce the number of turbine stages and thereby reduce the turbine cooling requirements. However, using higher-molecular-weight fluids also results in increased heat-exchanger sizes, so that a trade-off between cycle performance and cost would have to be considered.

(3) Of the fluids considered, using FL-85 as the bottoming-cycle working fluid offers the best performance potential when it is used in conjunction with a helium cycle with heat rejection at temperatures greater than 550°F . Using ammonia as the working fluid lowers the combined-cycle efficiency slightly but offers the potential advantage of much lower bottoming-cycle component costs.

5.2.4 Potassium/Steam System

The potassium/steam system studied by G.E. (fig. 21) includes a potassium cycle with a turbine inlet temperature of 1400°F that rejects its waste heat at a condensing temperature of 1100°F to a 3500-psig/ $1000^{\circ}\text{F}/1000^{\circ}\text{F}$ steam bottoming cycle. Heat is input to the potassium by a pressurized-fluidized-bed furnace operating at a pressure of 10 atmospheres and a bed temperature of 1750°F . In-bed desulfurization is accomplished by injecting dolomite into the bed. The furnace-pressurizing turbomachinery operates with a 1700°F turbine inlet temperature. A hot-gas filtering system (cyclones and granular bed filters) provided the necessary gas cleanup before admission to the gas turbine. The available gas turbine exhaust energy above a stack temperature of 300°F is recovered through feedwater heating in the steam cycle.

A total net power of 996 MWe is produced by the system, of which about 16 percent is contributed by the potassium turbine-generator, 63 percent by the steam turbine-generator, and 21 percent by the gas turbine-generator. The overall efficiency (coal pile to bus bar) was calculated to be 44.4 percent. The capital cost was estimated to be \$472/kWe before charges were added for A&E services, contingency, and escalation and interest during a construction period estimated to be 5.5 years and \$934/kWe including these charges. The COE was estimated at 39.8 mills/kW-hr, including capital, fuel, and O&M cost components of 29.6, 7.7, and 2.5 mills/kW-hr, respectively.



By comparing the costs of the potassium/steam system with the costs of the G.E. 1750⁰ F PFB, untopped, advanced steam system, which used a similar steam cycle and furnace-pressurizing system, it was possible to estimate the specific incremental cost, in \$/kWe, of the additional power produced by adding a potassium cycle between the furnace and the steam cycle. The specific incremental cost of the power produced by the potassium cycle was \$1006/kWe before charges were added for A&E services, contingency, and interest and escalation during construction, as compared with a specific capital cost of \$350/kWe for the untopped steam system. Final capital costs for these two systems, including the added charges, were \$1970/kWe and \$698/kWe, respectively. In a similar manner, the COE of the gross power produced by the potassium cycle alone was 68.4 mills/kW-hr, as compared with 32.7 mills/kW-hr for the untopped advanced steam system. Thus, although efficiency was increased from 40 percent to 44.4 percent by adding a potassium loop, the additional power obtained was much more expensive than that of the untopped advanced steam system. To lower the COE of the potassium/steam system to that of the untopped advanced steam system, it would be necessary to reduce the incremental costs attributable to the potassium-cycle portion of the powerplant to less than half the G.E. cost estimates.

Two variations of the configurations studied by G.E. in Phase 2 were examined by NASA. The first variation was designed to improve the system efficiency by using as much as possible of the pressurizing-gas-turbine exhaust energy to preheat the furnace combustion air before it is used for steam feedwater heating. This portion of the gas turbine exhaust energy will then be converted into electricity at the efficiency of the combined potassium/steam system rather than at the lower efficiency of the steam bottoming cycle alone. Although the overall efficiency could be increased by about 0.5 percentage point, the change is not likely to be economical. It increases the power produced by the potassium cycle but at relatively high incremental capital cost as compared with the substantially lower capital cost of the steam system.

The second variation was a concept that has been proposed in the literature for ameliorating the potential hot-corrosion and erosion problems of the pressurizing gas turbine operating in the PFB exhaust gases. The gas turbine inlet temperature is reduced by inserting an air preheater between the PFB exit and the turbine inlet. This approach also permits final filtering of small particles at the lower gas turbine inlet temperature with a "hot" electrostatic precipitator, thus eliminating the requirement for the costly, high-temperature, granular-bed filters. Turbine inlet temperature was reduced to 1000⁰ F through this technique, resulting in a drop in efficiency of approximately 2 percentage points from the reference system value of 44.4 percent. An additional drop of efficiency of 1 percentage point occurred as the turbine inlet temperature was further reduced to 800⁰ F. Slightly higher efficiencies might be obtainable by optimizing the steam feedwater heating system as the gas turbine inlet temperature is reduced. The specific cost of the modified system was estimated to be about

\$1002/kWe at 1000° F, increasing to about \$1090/kWe at 800° F, as compared with \$934/kWe for the reference system. The COE of the modified system was estimated to be 42.4 mills/kW-hr at 800° F, as compared with 39.8 mills/kW-hr for the reference system. Although reducing the inlet temperature to the pressurizing gas turbine relieves the problem of hot corrosion in the turbine, it causes a materials problem in the air preheater, which must now operate in the high-temperature gases leaving the PFB. In addition, the potential problem of hot corrosion in the potassium boiler tubes in the PFB still remains.

The results of the study suggest that the efficiency of an advanced steam powerplant with a PFB furnace can be increased from about 40 percent to 44.4 percent by adding a 1400° F potassium topping cycle. The resulting additional power is very costly, however, not only in terms of capital cost and COE, but also in terms of complexity and the additional failure modes and hazards associated with the use of an alkali-metal working fluid. The potassium system is expensive relative to the power it generates. A basic problem is that the potassium cycle is constrained to operate over a temperature range that does not exploit its full thermodynamic potential. The potassium turbine inlet temperature is limited by fluidized-bed and material constraints; and the condensing temperature is limited by large potassium volume flows and associated high turbine, ducting, and condenser costs. As a result, the cycle temperature difference available for turbine work is small, and the potassium cycle must handle a large energy flow without extracting much power. High-volume flows and costly materials then result in a high cost for each kilowatt of power generated by the potassium cycle.

5.2.5 Open-Cycle MHD/Steam System

The open-cycle MHD conceptual design done by G.E. in Phase 2 is similar to their Phase 1 base case 1. It is a coal-fired plant with 2500° F direct air preheat and 1932-MWe net output and is shown schematically in figure 22. Changes in configuration from Phase 1 to Phase 2 include the use of a diagonal wall generator to decrease inverter cost and a steam bottoming cycle with some regenerative feedwater heating interleaved between two sections of the economizer in order to obtain higher steam-cycle efficiency.

The combustor is assumed to operate fuel rich in order to reduce production of nitrogen oxides. After 85 percent of the slag is rejected and the potassium carbonate seed is added, the nominally 4600° F gases enter the MHD generator. After expansion in the generator to produce 1420 MW of power, the 3662° F gases flow into the first of a series of downstream heat exchangers, that is, the radiant furnace. In the radiant furnace the gases are cooled to a temperature level tolerable to the following convection heat exchangers by radiating to water walls formed by the steam-bottoming-cycle boiler tubes. Also the furnace volume is intended to be sufficient to provide about 2 seconds of residence time at a temperature near 3000° F in order to equilibrate the nitrogen oxides. The combustion is then completed by the addition of



Figure 22. - Simplified schematic diagram of Phase 2 conceptual powerplant - coal/open-cycle MHD/steam system.

secondary air.

The combustion gases then flow to the regenerative high-temperature air heater, where the combustion air is heated to 2500⁰ F. After they exit from the high-temperature air heater, the gases enter the secondary furnace, which contains the low-temperature air heater and steam superheater and reheater. Downstream of the secondary furnace, about 10 percent of the combustion gas is used for coal drying and the rest flows through the two sections of the steam-cycle economizer.

The seed reacts with the sulfur in the combustion products and is removed as potassium sulfate in the electrostatic precipitators downstream of the economizers. It is also assumed to be collected from the heat exchangers. It then enters a reprocessing system, where it is converted to potassium carbonate and recycled to the MHD combustor. Within this process the potassium sulfate is first reduced to a sulfide by an intermediate-Btu gas and is then reacted with carbon dioxide and water vapor to form potassium carbonate and hydrogen sulfide. The hydrogen sulfide flows to a Claus plant, where elemental sulfur is recovered.

Actually, two steam bottoming cycles are used. One drives the combustion air compressors (372 MW) and the other produces 587 MWe of electric output. Both have 3500-psig/1000⁰ F throttle conditions and a single reheat to 1000⁰ F.

The calculated overall efficiency is 48.3 percent, and the thermodynamic efficiency (which does not include auxiliary power and the intermediate-Btu gas used in seed reprocessing) is 54 percent. About 4 percentage points of this difference are due to seed reprocessing. (The intermediate-Btu fuel gas was assumed to be obtained from an off-site processing plant with 62 percent coal-to-fuel-gas conversion efficiency.) Alternative and potentially more efficient seed-reprocessing methods and the use of an integrated gasifier for seed reprocessing might reduce this loss by 1 to 2 percentage points. This is discussed in reference 7.

The total capital cost estimate is \$720/kWe, with a COE of 31.8 mills/kW-hr. The capital cost estimate for Phase 2 is about 35 percent lower than that for Phase 1. This is mainly due to a reduction of balance-of-plant costs, which resulted from a more effective powerplant layout in Phase 2. Although the sum of major-components cost estimates remained relatively unchanged, the low-temperature air heater and seed-reprocessing cost estimates increased substantially and the dc-to-ac inversion equipment and magnet costs estimates decreased.

The Phase 2 conceptual design was done as if the powerplant had reached a commercially mature state but was based on existing data. However, in the case of MHD, these existing data are somewhat limited or are based only on small-scale experiments and theoretical models. As a result, uncertainties in the results exist and will be resolved only by further experimental work. Areas of concern include the MHD generator and combustor performance, the verification of nitrogen oxides control and seed removal, and the compatibility of the slag- and

seed-laden gases with the construction materials. Resolution of these uncertainties might influence the power system configuration as well as the performance and cost estimates.

5.2.6 Molten-Carbonate Fuel Cell/Steam System

A molten-carbonate fuel cell with a steam bottoming cycle and integrated low-Btu gasifier was studied in Phase 2 by United Technologies Corp. (UTC) and Burns and Roe, Inc. The Phase 1 results indicated that fuel cells offer the potential for high efficiency. These electrochemical devices are not Carnot-cycle limited; and, in addition, high-temperature fuel cells allow efficient recovery of their waste heat by a bottoming cycle. The increase in reaction rates (reduced polarization) brought about by the high temperatures also helps the fuel cell approach its potential for high efficiency.

The three major subsystems of this Phase 2 system are the fuel cell, the steam bottoming cycle, and the gasifier/fuel-gas cleanup system. The schematic diagram of the system is shown in figure 23. The molten-carbonate fuel cell design is based on the fuel cell under development by UTC, which is currently operated at 1200⁰ F and ambient pressure. The ECAS design is based on pressurized operation (150 psia) in order to improve performance. Pressurized operation is used partially to overcome efficiency losses arising from the inherent dilution of the reactant gases. On the fuel-gas side (anode) of the cell, dilution results from using low-Btu gas, which is 46-percent nitrogen, as the fuel. Reactant dilution is more severe on the oxidant side (cathode) of the cell. The carbon dioxide required for the cathode reaction is supplied by circulating the anode exit gas to the cathode. Also, part of the cathode exit gas is recirculated. These gases contain nitrogen and water vapor, which further dilute the oxygen in the cathode inlet air.

Most of the cathode exit gas is recirculated to the fuel cell. Before being recirculated, these gases transfer the fuel cell waste heat to the bottoming cycle in the steam boiler and superheater. The remaining exhaust gas is used to power the turbocompressors, which provide compressed air for the fuel cell and for the gasifier. At the gas-turbine exit the gases are further cooled by transferring heat to the steam-cycle feedwater. The steam cycle has conventional 2400-psig/1000⁰ F throttle conditions with a single reheat to 1000⁰ F.

The gasifier selected for the conceptual design was the "U-Gas" system under development by the Institute of Gas Technology. It is a fluidized-bed, ash-agglomerating, air-blown gasifier. Exit gas conditions are 1900⁰ F and 200 psia. The fuel-gas cleanup system used in the conceptual design is based on the iron oxide sulfur-removal process under development by the ERDA Morgantown Energy Research Center. The operating temperature is nominally 1200⁰ F. The fuel-gas temperature is reduced from the gasifier exit temperature to the

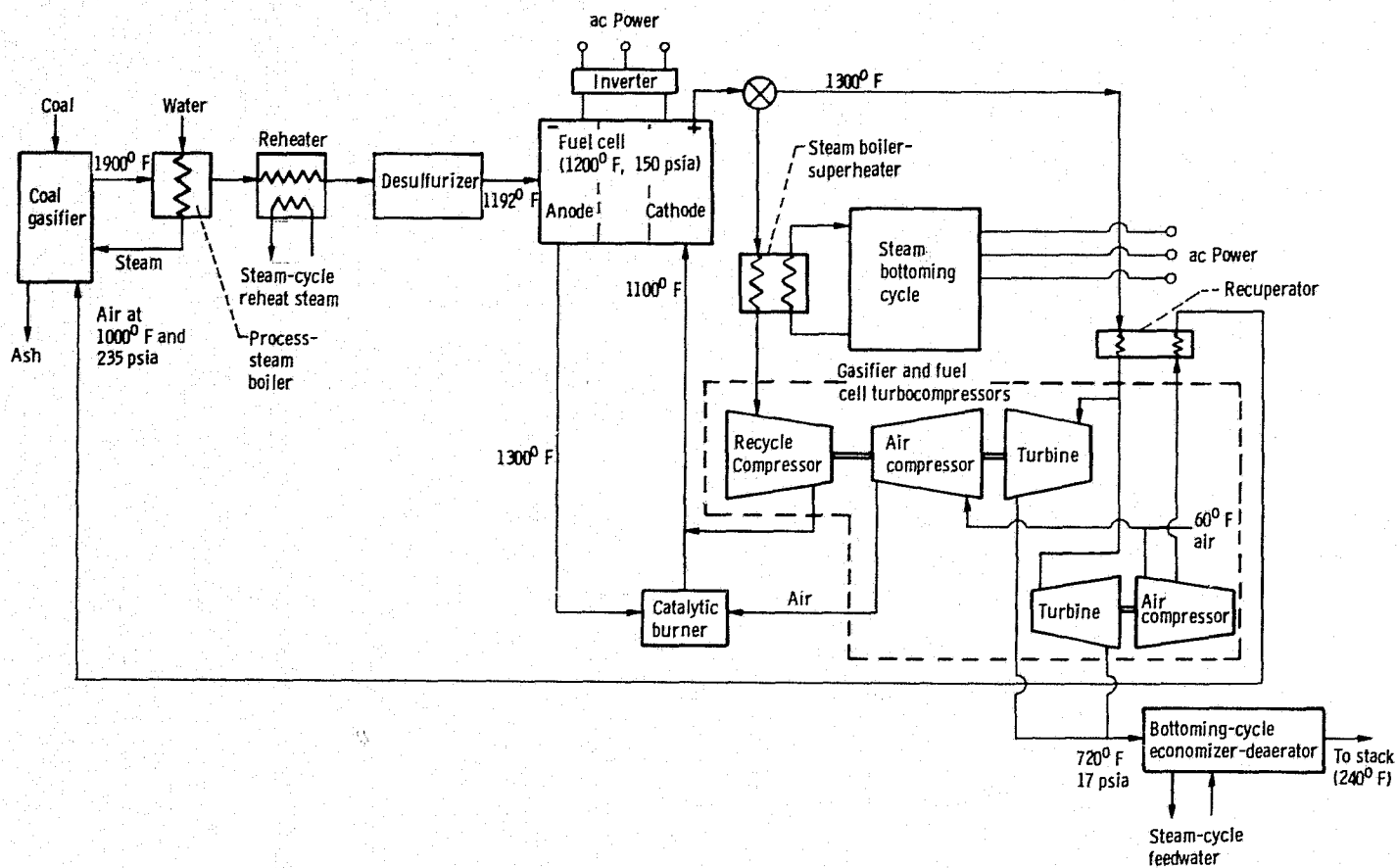


Figure 23. - Schematic diagram of low-Btu gasifier/molten-carbonate fuel cell/steam system.

iron-oxide-bed inlet temperature by transferring heat to the incoming gasifier process steam and to the steam-bottoming-cycle reheat.

The Phase 2 conceptual design has a net power output of 634 MWe. Sixty-six percent of the gross alternating-current electric power output is obtained from the fuel cell, the remainder from the steam bottoming cycle. The overall efficiency is 49.6 percent. The total capital cost is estimated to be \$595/kWe, and the COE is 29 mills/kW-hr.

The high overall efficiency results from the high efficiency of the fuel-cell topping cycle, the high availability of the waste heat for use in the bottoming cycle, and the integration of the gasifier with the energy conversion system. Prediction of fuel-cell performance is based on improvements from pressurized operation and on projected cell structural improvements. The performance increase due to structural improvements is a relatively modest extrapolation from the performance predicted for present-day cells if they were operated at pressure with a coal-derived fuel gas. A UTC analytical model was used in making these performance predictions.

A number of technological issues requiring resolution have been identified. These include the fuel-cell performance at pressure using a coal-derived fuel gas, the fuel-cell endurance, and the fuel-cell tolerance to contaminants in the fuel gas. A very important feature of the fuel cell is that these technological issues can be evaluated by small-scale cell experiments because of the modular nature of the fuel-cell stack. This can lead to significant savings in time and money during development.

5.3 RESEARCH AND DEVELOPMENT PLANS

In ECAS Phase 2, each contractor prepared a research and development plan for each conversion system studied in the conceptual design task, with the exception of the advanced steam systems. No R&D plans were requested for advanced steam systems because the primary advancement in these systems is in the furnace subsystem. The focus and major effort in ECAS were on the energy conversion systems, and it was not intended that sufficient detail be developed on the requisite furnace and gasifier subsystems to define all the problem areas. Further, the Fossil Energy Division of ERDA has many of these subsystems under development in various projects at this time. Within the scope of this study, the contractors were requested to address, in each development plan, the critical technological issues of such gasifiers and furnaces as they related to their respective powerplant concepts. However, estimating the associated development times and costs was considered outside the scope of the ECAS effort. Rather, each contractor was asked to indicate, in each plan, when such equipment would be required and to include appropriate acquisition and operation cost estimates. Therefore, the development plans presented were neither paced nor constrained by these critical subsystems.

The contractors were also requested to base their development plan cost and time estimates on a moderately paced (neither a crash program nor a stretched-out program), logically phased level of effort that would achieve successful development with a minimum of parallel risks. The purpose of these plans is to add to the information base necessary for an assessment of the various advanced fossil-fueled conversion systems and to delineate the research and development efforts required to bring these systems from their present state of technology to demonstration at utility powerplant scale.

5.3.1 Overall Summary of Research and Development Plans

The estimated cost (in mid-1975 dollars) and time necessary to bring each conversion system through demonstration plant operation are summarized in figure 24(a). The development times range from 9 years for the molten-carbonate fuel cell system to 19 years for the open-cycle MHD system. Development costs (including demonstration) range from about \$200 million to \$1.5 billion in nonescalated, mid-1975 dollars. The size of the demonstration plant differed for each system studied. The total development costs per kilowatt of demonstration plant output are shown in figure 24(b).

The information presented in figure 24 is also given in table VI, together with the breakdown of cost estimates according to five phases. In the interest of uniformity of presentation, in preparing table VI the contractor cost categories were rearranged as necessary and, as nearly as possible, to fit the following five-phase format:

- (1) Phase 1: Program definition
 - (a) Cycle selection
 - (b) Preliminary powerplant design
 - (c) Component requirements definition
 - (d) Component test program definition
- (2) Phase 2: Component development
 - (a) Materials technology
 - (b) Component design
 - (c) Bench, subscale, and/or scale testing
- (3) Phase 3: Technological readiness test
 - (a) System design
 - (b) System manufacture
 - (c) Steady-state and transient test of subsystem at appropriate scale
- (4) Phase 4: Pilot plant
 - (a) Design
 - (b) Manufacture
 - (c) Assembly of all elements of complete plant as appropriate

○ General Electric
 □ Westinghouse
 △ United Technologies

A Open-cycle MHD/steam
 B Potassium/steam
 C Closed-cycle gas turbine/organic
 D Low-Btu gasifier/gas turbine/steam
 E Semiclean-fuel-fired gas turbine/steam
 F Molten-carbonate fuel cell/steam

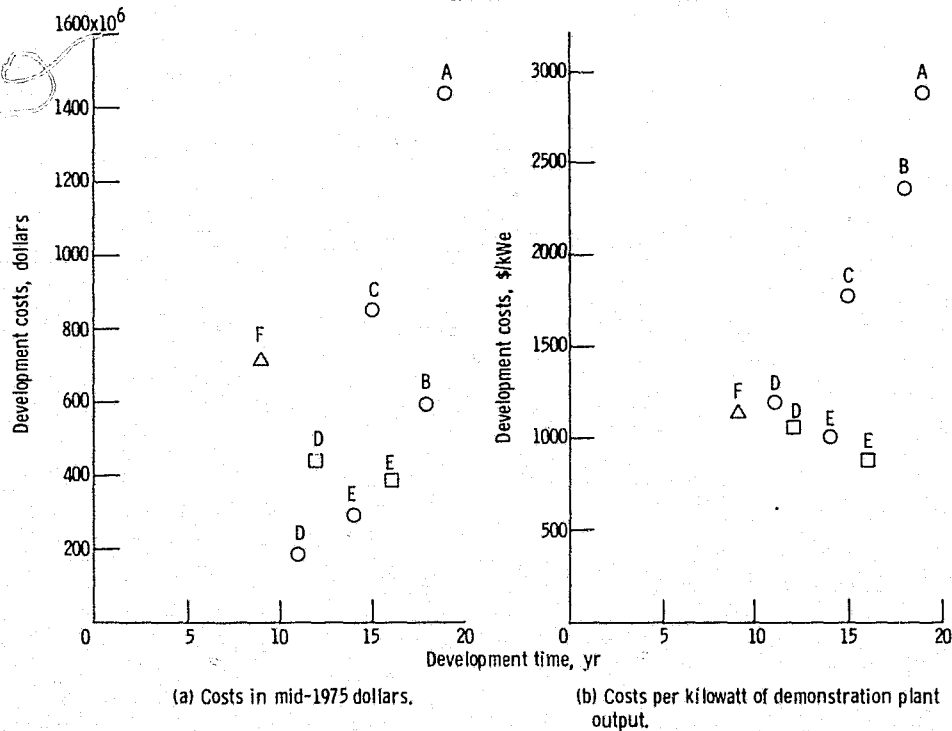


Figure 24. - Summary of contractor-estimated development costs and times for ECAS advanced energy conversion systems, excluding gasifiers and furnaces.

(d) Testing to establish integration, operation, control, and durability

(5) Phase 5: Demonstration plant

(a) Design and manufacture of hardware

(b) Design and construction of demonstration plant

(c) Initiation of demonstration testing

Blanks in table VI reflect the fact that the contractor plan does not address that category of effort. For example, in the coal/open-cycle MHD/steam system plan, the contractor assumed that the program has been defined and is currently in the component development phase; therefore, no resources were allocated for a program definition phase specific to the demonstration of the ECAS Phase 2 conceptual design powerplant. Several of the plans omit the subsystem and/or system technology readiness verification (phase 3) and optimistically go from component development to pilot plant or prototype demonstration. The reader is once again cautioned

TABLE VI. - ECAS CONTRACTOR-ESTIMATED DEVELOPMENT COSTS AND TIMES FOR PHASE 2 POWERPLANTS

System	Contractor	Plant size, MWe net		Phase ^a						Development time through demonstration operation, yr	Ratio of total cost to demonstration output, \$/kWe
		Commer- cial plant	Demonstra- tion plant	1	2	3	4	5	Total		
				Development cost, ^b million dollars							
Low-Btu gasifier/gas turbine/steam	General Electric	585	146	1.1	20	--	25	137 (11)	183	11	1253
	Westinghouse	786	393	1.7	53	38	46	301 (8)	439	12	1117
Low-Btu gasifier/molten-carbonate fuel cell/steam	United Technologies	635	635	1.6	12.4	25	34	642 (?)	715	9	1125
Semiclean-fuel-fired gas turbine/steam	General Electric	846	282	4.0	48	59	39	142 (25)	291	14	1032
	Westinghouse	874	435	2.3	41	42	64	239 (8)	389	16	894
PFB/potassium/steam	General Electric	922	245	1.3	76		230	286 (19)	593	18	2420
AFB/closed-cycle gas turbine/organic	General Electric	476	476	3.7	14	46	136	647 (32)	847	15	1780
Coal/open-cycle MHD/steam	General Electric	1932	500		^c 259	--	^d 743	442 (75)	1444	19	2890

^a1 - Program definition; 2 - Component development; 3 - Technology readiness verification; 4 - Pilot plant and/or prototype development; 5 - Demonstration plant buildup and operation.

^bNumbers in parentheses denote amount allocated in total cost for demonstration plant operation.

^cIncludes planned \$142 million for operation of CDIF for 12 yr beyond planned phase 2 operation.

^dIncludes \$360 million for operation of ETF beyond planned phase 3 operation.

that the development costs presented here do not encompass the requisite gasifiers, furnaces, or coal-to-liquid-fuel processing equipment for any of the systems but only the energy conversion system itself.

As shown in the table, the cost of the demonstration plant represents a major portion of the total cost for all systems except MHD. Further, the cost of the demonstration plant is proportional to its size. For the systems studied, the various demonstration plants range in size from about 150 MWe to over 600 MWe. As a result, it may be most appropriate to compare the costs on the basis of dollars per kilowatt of demonstration plant size. Inspection of table VI reveals that the nearer-term systems should take about 12 years to develop at a cost, in mid-1975 dollars, of \$1000 to \$1200 per kilowatt-electric for the conversion system. For the technically more difficult systems, the development time is of the order of 20 years with an associated cost of \$2000 to \$3000 per kilowatt-electric. The combined-cycle plants fueled with coal-derived liquid fuel are intermediate with respect to probable development time but hold the promise of the lowest development costs.

In all but two cases the demonstration plant costs (phase 5) represent 50 to 70 percent of the total program costs. In the case of MHD it is, however, only 25 percent of the total. This reflects the technological uncertainties that must be addressed and the large-scale experiments needed to resolve them. In the case of the molten-carbonate fuel cell system, the demonstration plant costs are 90 percent of the total. This reflects the choice of a full-size demonstration plant and the ability to address the technological issues in small-scale experiments because of the modular nature of the system. Again, however, it should be remembered that the development costs for the gasifier and fuel-gas cleanup system are not included.

5.3.2 Technological Considerations and Uncertainties

The various powerplant concepts studied in ECAS vary widely with respect to the present status of applicable technologies. For all these advanced energy conversion systems, there are at least one or two principal uncertainties pertaining to the technical feasibility and economic viability of the system. For those systems for which there is no previous operational experience with the concept and for which there is a relatively small technology base, the list of principal uncertainties increases and the individual magnitude of the uncertainties becomes more pronounced.

The Phase 2 conceptual designs were done as if each system had reached a state of commercial maturity. As part of the R&D plans the contractors discussed the principal technological issues that must be resolved to bring each powerplant to the assumed state of maturity. These issues and uncertainties are identified and discussed in section 6.0 of reference 7.

There was no formal attempt in ECAS to order the systems according to the degree of uncertainty or difficulty in bringing them to the assumed state of maturity (beyond the compar-

ison of R&D plans as in the previous section). This would necessarily involve the comparison of individual and dissimilar problems for each system and a weighing of these for each system to arrive at an overall system uncertainty level. Such a task would be imprecise and certainly without uniform agreement. However, it is clear that the systems are presently at radically different levels of technological maturity. The following discussion summarizes the salient technological considerations that can be anticipated to influence development risk, or uncertainty, in each system for which development plans were provided in ECAS. The steam systems, for which no R&D plans were evolved, would have the least uncertainty.

5.3.2.1 Low-Btu gasifier/gas turbine/steam system. - Combined gas turbine/steam turbine powerplants operating with natural gas or distillate fuel are in service today, principally for intermediate-load applications. Similarly, commercial coal-gasification processes exist, and such gasification plants have been in service for a number of years. The success of the low-Btu gasifier/gas turbine/steam systems as defined in ECAS hinges on the successful development of the advanced gasifiers and gas-cleanup systems and the favorable application of advanced air-cooling concepts to low-Btu-fired gas turbines operating at the 2500⁰ F level. With respect to the gasifiers, ERDA is currently funding development efforts on several advanced coal-gasification processes. The technology for the advanced fixed-bed gasifier proposed by G.E. is closer to hand than that for the fluidized-bed approach selected by Westinghouse. Similarly, the gas turbine design (film cooling) selected by G.E. appears less technically uncertain than that associated with the Westinghouse proposed concept (transpiration cooling).

5.3.2.2 Low-Btu gasifier/molten-carbonate fuel cell/steam system. - As yet there are no commercial fuel cell powerplants of any kind in utility service, so there is no operational experience base for this system. There is a major effort in place to bring the phosphoric-acid fuel cell system into commercial service; however, any extensive field experience is several years away. Molten-carbonate fuel cell technology is still in its infancy, and significant technical progress is required in order to produce cells embodying the power density, efficiency, and fuel-gas-impurity tolerance characteristics assumed for the conceptual design plant. A key advantage that the fuel cell system holds over the other ECAS systems is the highly modular character of the fuel cell itself. The technological problems can be investigated and resolved at very small scale. Performance characteristics of small cells are readily scaled to characterize full-size systems. As with the low-Btu-fired combined-cycle systems, the ECAS molten-carbonate fuel cell system requires the development of an advanced fluidized-bed gasifier.

5.3.2.3 Semiclean-fuel-fired gas turbine/steam system. - These systems require major advancements over current combined-cycle systems with respect to combustor development, component cooling, and materials usage. Developing the technology to use semiclean fuels acceptably at high firing temperatures is particularly challenging. No less challenging is the requirement to develop ceramic hot-section stationary components for both G.E. and Westinghouse

and, in particular, the rotating components proposed by Westinghouse. To help meet this challenge, G.E. proposes the extensive use of water cooling, a concept still requiring substantial technological development and verification to achieve successful application to utility gas turbines.

5.3.2.4 PFB/potassium/steam system. - The principal technological uncertainties associated with the PFB/potassium/steam system, in addition to design development for hazards avoidance and containment, include mechanical integrity and fire-side corrosion of the in-bed potassium-boiler tubes, the feasibility of producing large-diameter potassium-turbine disks, and the development of the technology and suppliers for producing all the ancillary alkali-metal-loop components of the appropriate size. Prior component experience was directed toward space power application and is limited to much smaller sizes than currently under investigation. The consequences of failure and the time to repair the system have not been fully defined and will certainly have significant effects on availability.

5.3.2.5 AFB/closed-cycle gas turbine/steam system. - All three major subsystems associated with the AFB/closed-cycle gas turbine/steam concept as studied in ECAS Phase 2 require significant developmental efforts to establish technical feasibility and/or economic viability. The AFB furnace concept represents a significant departure from the furnace concepts proposed for other advanced energy conversion systems. The feasibility of using in-bed, ceramic, tubular heat transfer surfaces is particularly uncertain. In principle, the design of the helium turbomachinery for this plant is straightforward; however, the absence of an extensive experience base is cause for concern about the straightforward development of a 400-MWe, 1850^o F helium turbocompressor. Similar concern applies to the commercialization of the 144-MWe organic turbine without allowance for development. The lack of information regarding the long-term stability of the organic fluid and the requirement for virtual zero-leak operation are added elements of concern pertaining to this bottoming subsystem.

5.3.2.6 Coal/open-cycle MHD/steam system. - The coal/open-cycle MHD/steam system is one of the most technically ambitious undertakings of the advanced concepts. There are significant technical uncertainties associated with nearly all of the major components of the MHD system itself. For many of these components, the expected operating environment and hence materials requirements are not defined well enough to establish firm design approaches. A characteristic of the MHD powerplant is that the critical technical uncertainties require resolution in large, or full-scale experiments.

5.3.3 Concluding Remarks

The purpose of the ECAS research and development plans, as stated at the beginning of this section, is to define the technological efforts that are required to bring the various energy conversion systems from their present states of technology to demonstration of their conceptual

design characteristics at utility-powerplant scale. A review of the plans suggests, as would be expected, that the more mature the technology, the firmer is the grasp on the technical problems to be faced, with a correspondingly sounder understanding of the probable paths to their resolution.

All the plans tend to be very success oriented and hence optimistic with respect to the estimated development time. For several plans, the demonstration plant efforts are begun prematurely. In others, there is evidence of significant parallel risk in the earlier program phases. None of the plans allows for a government-funded, phased development program. However, with proper consideration of the shortcomings and limitations, the development plans provide meaningful inputs to a first-order comparative assessment and evaluation of the various fossil-fuel-fired powerplant concepts.

5.4 IMPLEMENTATION ASSESSMENT

5.4.1 Factors Considered

The contractors assessed the prospects for commercial implementation of each design by evaluating each system according to a number of quantitative and qualitative implementation factors. The conceptual design task of Phase 2 resulted in cost and performance estimates for each of the systems. These estimates provide a basis for assessing some of the nominal quantitative factors, such as economic viability. The qualitative factors form the basis for assessing the potential availability and flexibility of the designs. These must be included as discriminators when they can be quantified. The NASA review in reference 7 of implementation assessments examined the sensitivity of COE to several uncertainties, summarized the contractors' assessments, and commented on the relative potential availability and flexibility of the designs.

The contractors were provided by NASA with guidelines for factors affecting the implementation of powerplants. To facilitate discussion of contractor results, each contractor's assessments were interpreted as a good, fair, or poor rating. This is discussed in reference 7. Comparing contractor assessments for like systems shows the subjective nature of such an assessment. For example, while the two PFB/steam plants studied by G.E. and Westinghouse are essentially the same in design, there were several significant differences in factor assessments. This should be recognized in evaluating all the assessments.

All powerplants were designed for baseload use, and the natural resource demands, environmental intrusions, and siting needs were similar, as indicated by the contractors' results. Those designs requiring limestone or dolomite sorbent have disposal requirements that designs without sorbent do not have. These disposal requirements may have significant impact in certain geographic locations with respect to acceptable plant siting. The semiclean-fuel-fired gas

turbine/steam plants have nitrogen oxides emission problems that need further resolution. Land estimates differed substantially among the contractors because of differences in layout philosophy. The natural resource requirements and emissions estimates for each system are summarized in section 5.1.4.

The flexibility in meeting more-advanced emissions goals than those specified for the study (section 3.5) may affect implementation prospects. To meet the sulfur dioxide standard, 6 of the 11 ECAS systems use in-bed desulfurization with throwaway limestone or dolomite sorbent, one uses hot-fuel-gas cleanup in regenerative iron oxide beds with sulfur recovery, two depend on the low sulfur content of the coal-derived liquid H-coal, and the MHD system uses potassium carbonate seed material to react with the sulfur in order to produce potassium sulfate, which is regenerated for elemental sulfur and potassium carbonate recovery.

The more restrictive sulfur dioxide goals specified in ECAS require about an order-of-magnitude reduction in emissions. To achieve these targets would require different approaches for the several desulfurization methods. The in-bed desulfurization systems may accomplish the reduction by increasing the ratio of sorbent to coal and by increasing the residence time in the beds. This would require larger equipment and increased sorbent consumption. The MHD system would require successful capture of virtually all the sulfur by the seed material and increased electrostatic precipitator capacity. The cold-fuel-gas method of cleanup can more readily achieve the advanced goals for the gasifier systems at some loss in fuel conversion efficiency relative to the hot-gas cleanup systems. Further reduction in sulfur dioxide emissions from the fuel cell powerplant could be achieved by adding zinc oxide beds and a tail-gas plant to the Allied sulfur recovery plant.

All the coal-fired, fixed- and fluidized-bed systems produce low nitrogen oxides emissions because of their low combustion temperatures. The nitrogen oxides are assumed to be controlled in the MHD system by burning the coal with a deficiency of air and then equilibrating the nitrogen oxides at the 3000^o F level in a downstream heat exchanger before additional air is added to complete combustion. The estimated nitrogen oxides emissions are, in fact, projected to be low enough to meet or just slightly exceed the advanced targets specified for the study, which require a 60- to 80-percent reduction in nitrogen oxides. The coal-derived fuel-oil systems exceed the nitrogen oxide standard because of fuel-bound nitrogen and high combustion temperatures. Improved combustion techniques may reduce thermal and fuel-bound nitrogen oxides. The latter will be the controlling factor for meeting even the standard study limit.

The particulate emissions standard in this study is 0.1 pound per million Btu of both coal and liquid fuels. The more-advanced goals considered would require a reduction of one to two orders of magnitude from the standard. Using cyclones and electrostatic precipitators will achieve the current standard. Filter beds provide an order-of-magnitude improvement, while

a cold-gas cleanup with water wash would substantially reduce particulate emissions. Either would increase cost.

The assessment of the potential for retrofitting existing steam powerplants varied among contractors as a result of differences in general outlook as much as of differences in powerplant features. The G.E. rating for the retrofit factor was "poor" for all systems; the Westinghouse and UTC project teams, however, considered repowering of old steam powerplants an attractive possibility.

The ECAS systems were designed to include as much modularity as possible. This shifts construction from the field to the factory, which should increase the opportunity for quality control and, therefore, reliability. Although large powerplants enjoy economy-of-scale advantages, a trend of low reliability for recent larger powerplants has been observed. Modularity allows the benefits of scale and at the same time permits design for less vulnerability to total outages from single-point failures and for redundancy of major components. Most of the systems incorporate modular construction and layout, which allows partial operation during maintenance. The MHD/steam system is designed as a series of large units, with multiple single-point failure possibilities that would result in total outage. The G.E. low-Btu gasifier/gas turbine/steam system design illustrates the opportunity for redundancy afforded by modularity in that it provides excess gasifier capacity to serve the gas turbine.

All system designs use coal or coal-derived semiclean fuels. Each can be designed to accommodate a variety of coal characteristics.

The flexibility of conceptual designs to accommodate technological evolution and to accept retrofit with new components may allow designs to be introduced sooner and may increase implementation opportunity. Some measure of equipment update opportunity is available for each of the conceptual designs. Possibilities include the addition of regenerative systems to the in-bed desulfurization systems, gas-turbine component upgrading at regularly scheduled servicing, and fuel cell module replacement. Providing for replacement of technologically evolving components can increase the flexibility of a powerplant to keep technological performance current while maintaining plant availability.

The concern for availability of critical materials should focus technology on lessening the need for imported materials, such as on reducing nickel loading in the porous electrodes of the fuel cells. Least vulnerable of the ECAS designs from this standpoint are the low-Btu gasifier/gas turbine/steam systems and the semiclean-fuel-fired gas turbine/steam systems.

Appraisal of implementation prospects should include an assessment of the changes required in the marketplace to accept a new design. Those systems that rely on evolutionary extensions of boilers, gas turbines, or steam turbines (for which there already exist viable markets, manufacturing capability, and technical expertise) should have an advantage. In addition, the risk of losing leadership in current systems if engineering resources are overextended in new ventures much be weighted.

5.4.2 Effect of Uncertainties in Cost Estimates

The ECAS contractors estimated the costs for all concepts as if the technology for each were fully developed or mature. In fact, the technology for many parts of the conceptual designs has not been developed; therefore, the cost estimates must contain uncertainties. In an attempt to quantify the uncertainties and to determine their relative effects on COE, each major identifiable part of the cost of each concept was placed in one of the following categories:

- (1) Current technology - equipment of the type that may be purchased at the present time
- (2) Near-term technology - equipment requiring development for this particular application, that is, equipment that has enough development background to indicate it will function as designed but requires further development to demonstrate functioning under the size, environment, lifetime, etc., needed for the ECAS designs
- (3) Advanced technology - equipment that has neither the design practice nor the development background sufficient to predict with confidence that the design approach used in ECAS is viable and that, therefore, has more uncertainties associated with it than the previous category

Placing the capital costs of each item for each system into these categories is understandably subject to opinion and judgment. But the purpose of this analysis was to show the relative effects for the systems, not the absolute uncertainty of the results, and an attempt was made to categorize each system on a consistent basis. Because of the level of cost detail generated in ECAS, the categorization could be and was done down to the component level. Whenever differences in technological level within a component existed, the entire component was assigned to the more-advanced category. An example is the ceramic gas turbine, where only the ceramic technology is appropriate to the advanced-technology category. But the entire component was assigned to this category even though the compressor and generator clearly are not appropriate to this category. When significant doubt existed with respect to the appropriate category, the more-advanced category was selected. The intent of the calculations was to dramatize the sensitivity of the capital costs to uncertainties in the cost estimating.

The total installed costs for each major component were used in order to account for differences between site-erected components and factory-assembled units. Since the uncertainty was to be expressed as a relative cost uncertainty, all equipment in the current-technology category was assumed to be capable of performing as designed for the cost listed by the contractors. Equipment placed in the second and third categories was assumed to be uncertain in estimated cost for the specified performance; that is, uncertainties in the projected performance are not included. It was further assumed that, if costs changed, they would increase rather than decrease. The factors applied to the three uncertainty levels are shown in table VII. The total system capital costs and the percentage associated with each of the uncer-

tainty categories are given in table VIII. The capital costs are given in "constant mid-1975 dollars," this approach being described in section 5.1. The major portion of powerplant capital cost is in the current-technology category for all the systems and includes such items as steam turbine generators and balance-of-plant equipment. Thus, uncertainties are applied only to a portion of the capital cost, which in turn is a portion of the total cost of electricity.

Table IX compares the COE and capital costs at each of the relative uncertainty levels, with all costs expressed in constant mid-1975 dollars. Most systems are subject to a 25- to 35-percent increase in capital cost at uncertainty level C. Exceptions are the AFB/steam sys-

TABLE VII. - RELATIVE UNCERTAINTY

LEVELS FOR THREE UNCERTAINTY

CATEGORIES

Relative uncertainty level	Uncertainty category		
	Current technology	Near-term technology	Advanced technology
	Uncertainty factor applied to costs		
A	1.0	1.1	1.25
B	1.0	1.2	1.5
C	1.0	1.4	2.0

TABLE VIII. - SYSTEM COST CATEGORIZATION

System	Contractor	Percentage of capital cost associated with -		
		Current technology	Near-term technology	Advanced technology
1 - AFB/steam	General Electric	84	16	0
2 - PFB/steam	General Electric	71	9	20
3 - PFB/steam	Westinghouse	78	9	13
4 - PFB/potassium/steam	General Electric	58	14	28
5 - AFB/closed-cycle gas turbine/organic	General Electric	56	17	27
6 - Low-Btu gasifier/gas turbine/steam	General Electric	73	27	0
7 - Low-Btu gasifier/gas turbine/steam	Westinghouse	60	19	21
8 - Semiclean-fuel-fired gas turbine/steam	Westinghouse	68	0	32
9 - Semiclean-fuel-fired gas turbine/steam	General Electric	68	0	32
10 - Coal/open-cycle MHD/steam	General Electric	53	28	19
11 - Low-Btu gasifier/molten-carbonate fuel cell/steam	United Technologies	61	12	27

TABLE IX. - EFFECT OF RELATIVE COST UNCERTAINTIES ON CAPITAL COST AND COST OF ELECTRICITY

System	Contractor	Base values, in constant mid-1975 dollars		Capital cost, \$/kWe, at uncertainty level -			Cost of electricity, mills/kW-hr, at uncertainty level -		
		Capital cost, \$/kWe	Cost of electricity, mill/kW-hr	A	B	C	A	B	C
1 - AFB/steam	General Electric	447	25.8	454	461	476	26.1	26.3	26.7
2 - PFB/steam	General Electric	511	27.4	435	459	508	28.3	29.2	31.1
3 - PFB/steam	Westinghouse	401	23.5	418	434	468	24.0	24.5	25.5
4 - PFB/potassium/steam	General Electric	660	31.2	715	771	882	32.9	34.6	38.1
5 - AFB/closed-cycle gas turbine/ organic	General Electric	899	38.8	975	1051	1203	41.2	43.6	48.4
6 - Low-Btu gasifier/gas turbine/steam	General Electric	562	28.6	577	592	623	29.1	29.6	30.5
7 - Low-Btu gasifier/gas turbine/steam	Westinghouse	448	23.9	480	512	576	24.9	25.9	27.9
8 - Semiclean-fuel-fired gas turbine/steam	Westinghouse	256	23.7	276	297	338	24.3	25.0	25.6
9 - Semiclean-fuel-fired gas turbine/steam	General Electric	305	25.9	329	354	403	26.7	27.4	28.9
10 - Coal/open-cycle MHD/steam	General Electric	478	24.1	513	555	621	25.2	26.5	28.6
11 - Low-Btu gasifier/molten-carbonate fuel cell/steam	United Technologies	433	23.9	467	502	571	24.8	25.9	28.1

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tem, at 6 percent; the low-Btu gasifier/gas turbine/steam system of G.E., at 11 percent; and the PFB/steam system of Westinghouse, at 17 percent. The systems with the least sensitive COE's are the semiclean-fuel-fired gas turbine/steam systems, because their COE's are dominated by their fuel costs. Therefore, the maximum uncertainty for these two systems is in the semiclean-fuel costs. The remainder of the systems are grouped rather closely as far as percentage of increase in COE is concerned, and there is no major rearrangement in the relative cost estimates as a result of applying these cost uncertainty factors.

6.0 PERSPECTIVE ON RESULTS

All the systems included in ECAS have been studied previously to various levels of detail. However, because these past studies have been done with different scopes, to different levels of detail, and according to different ground rules and assumptions, it has been difficult to make consistent comparisons of the systems. ECAS is intended to add to these prior studies by analyzing all the systems to the same level of detail with common ground rules and consistent assumptions. It was intended as a framework for continued comparisons and further analysis of these alternative systems.

The approach and scope of ECAS are described in section 2.2. The study was performed with multiple, concurrent contracts with the expectation that different teams would take different design approaches for similar systems, which would lead to real and valid differences in the results. Using common ground rules and a similar format for presentation of the results then allowed focus on the real technical differences and direct comparison and reconciliation of the results by NASA. The contracts were not, however, entirely parallel in content. Because of a combination of factors (programmatic and time constraints, differences in contractor team experience, and the desire to broaden the overall scope of coverage of the study), the areas of emphasis in Phase 1 and the systems considered in Phase 2 in some cases differed between contracts. Overlap in coverage was, however, maintained in many cases to include direct comparisons of results between contractors.

In recognition of prior analyses, the Phase 1 parametric analysis started with a pre-selected matrix of cases. These were selected on the basis of the collective judgment and experience of the industry and government participants. There was little opportunity for iteration of the results of individual systems to obtain further improvements relative to the others (although this was done in some cases). Because all the systems were analyzed together on a common basis, in many cases the results served to define areas of further investigation for potential improvements that were not obvious to even the system advocates, based on prior analyses, at the beginning of the study.

In general, because of the breadth of coverage, Phase 1 results did serve as a basis for selecting a much smaller number of cases for more-detailed consideration in Phase 2. And it did provide the basis from which to proceed to conceptual design of those systems selected for Phase 2. The fact that a system was not selected for Phase 2 does not necessarily imply that no further consideration is warranted. Systems not selected include

- (1) Those for which the technology or design base was insufficient to permit, within given resource constraints, the ability to adequately treat the system at a conceptual design level

- (2) Those that could not be expected to show their maximum potential on a comparative basis for the ECAS area of emphasis, which is primarily large baseload central-station powerplants

As explained in section 2.2, Phase 2 consisted of conceptual designs, an implementation assessment, and an estimate of R&D plans for each system design. The conceptual designs done in Phase 2 each represent a different level of technology and hence have different levels of uncertainty associated with the results. The more distant the expected date of commercialization or the more immature the present technological status of a system, the more difficult it is to estimate the component or subsystem cost and performance. In the nearer-term systems, these uncertainties are mainly in the costs of some of the components; in the far-term systems they extend to a larger fraction of the components and to the system performance as well. Rather than conceal the effects of these uncertainties in the conceptual-design cost and performance results, they were treated as if each system had reached a state of commercial maturity. The uncertainties were then dealt with separately in the implementation assessments and R&D plans.

The conceptual-design cost and performance results obviously do not prove the validity of the technical assumptions made relative to the component performance and design approach, but they do illustrate the potential for the system if the assumed mature state is reached. The implementation assessment addresses the factors that would affect the adoption of a system by the utility industry. And the R&D plans estimate the time and resources needed to reach the state of maturity assumed for each design. Comparisons of cost and performance are therefore incomplete without considering the implementation assessment and R&D plan, including the relative technical and economic uncertainties and the estimated date of commercialization.

The relative uncertainties in the results for different systems cannot be quantified with precision and uniform agreement. The approach taken in ECAS was an attempt to separate this issue from the actual analysis of cost and performance of the conceptual designs. Although the relative uncertainties in achieving the technical assumptions in the designs and attaining the goals in the R&D plans cannot readily be quantified, they were discussed and ranked in references 4 to 7 and in section 5.3.2. The relative uncertainties in capital cost estimates as a result of differences in present technological status were evaluated in a parametric manner in section 5.4.2. This showed that even in the more-advanced systems the overall capital cost estimates are dominated by state-of-the-art equipment and balance-of-plant costs and that the effect of the uncertainty in estimates of individual component costs on over-

all cost is consequently considerably reduced. Therefore, even though significant cost uncertainties exist for advanced-technology components, valid comparisons can be made of the results in order to assist in formulating R&D emphases and in defining national benefits.

Lewis Research Center,
National Aeronautics and Space Administration,
Cleveland, Ohio, September 23, 1977,
778-11.

APPENDIX A

SUMMARY OF PHASE 1 PARAMETRIC RESULTS BY SYSTEM

The overall results of Phase 1 are summarized in section 4.1. The efficiency and cost of electricity (COE) results for the parametric cases of each system are shown in figures 2 and 3. A general description of the parametric cases considered for each system and the range of results obtained are contained in this appendix for each system. The ranges of the representative results of each system are also summarized in table X.

ADVANCED STEAM

The emphasis for the advanced steam system in Phase 1 was on investigating those systems using advanced furnace concepts and/or increased steam turbine temperatures (to the 1200° F level or higher).

Both contractors investigated four combustion techniques: conventional furnace (CF), atmospheric-fluidized-bed furnace (AFB), pressurized-fluidized-bed furnace (PFB) to burn

TABLE X. - RANGE OF RESULTS

System	General Electric			Westinghouse		
	Cost of electricity, mills/kW-hr	Overall energy efficiency, percent	Powerplant efficiency, percent	Cost of electricity, mills/kW-hr	Overall energy efficiency, percent	Powerplant efficiency, percent
Advanced steam	30 - 38	34 - 40	34 - 40	21 - 35	34 - 43	34 - 43
Open-cycle gas turbine:						
No bottoming	31 - 37	15 - 19	31 - 37	28 - 42	12 - 22	25 - 44
Organic bottoming	33 - 39	20 - 22	42 - 43	33 - 36	22 - 24	42 - 48
Combined cycle	23 - 33	21 - 37	34 - 48	24 - 34	20 - 42	38 - 49
Closed-cycle gas turbine:						
No bottoming	34 - 49	15 - 34	26 - 34	30 - 50	14 - 35	29 - 37
Organic bottoming	38 - 43	35 - 38	35 - 38	35 - 45	17 - 22	35 - 43
Steam bottoming	36 - 45	30 - 34	30 - 33	30 - 43	16 - 38	33 - 44
Supercritical CO ₂	50 - 78	35 - 41	35 - 41	-----	-----	-----
Liquid-metal Rankine	40 - 61	34 - 41	34 - 41	29 - 37	32 - 44	32 - 44
Open-cycle MHD	41 - 48	40 - 53	44 - 59	27 - 42	44 - 54	44 - 54
Closed-cycle MHD	46 - 73	26 - 46	35 - 46	68 - 80	41 - 46	41 - 50
Liquid-metal MHD	58 - 110	17 - 39	28 - 39	34 - 78	34 - 39	34 - 39
Fuel cells:						
High temperature	42 - 45	24 - 34	24 - 34	35 - 60	27 - 53	32 - 70
Low temperature	31 - 60	13 - 31	25 - 51	40 - 61	24 - 31	30 - 38

coal, and pressurized furnace (PF) to burn low-Btu gas from an integrated gasifier. Both contractors also investigated a range of turbine throttle temperatures and pressures, reheat temperatures, numbers of reheats, powerplant sizes, heat rejection methods, types of coal, and other system parameters. General Electric evaluated a total of 28 parametric points around a base case using an atmospheric-fluidized-bed furnace and steam conditions of 3500 psig/1200^o F/1000^o F. Westinghouse evaluated a total of 180 parametric points around three base cases using conventional, pressurized-fluidized-bed, and pressurized furnaces, respectively. All Westinghouse base cases had steam conditions of 3500 psig/1000^o F/1000^o F. The Westinghouse study emphasized the use of PFB's, PF's, and CF's, and the G.E. study AFB's. The different emphases on furnace types thus complemented each other and enabled a broader coverage of parametric variations to be investigated.

As shown in table X, the General Electric results showed overall energy efficiencies from 34 to 40 percent and COE's from 30 to 38 mills/kW-hr. Westinghouse results showed an efficiency range of 34 to 43 percent and a COE range of 21 to 35 mills/kW-hr. The range of steam conditions investigated by Westinghouse, which included higher pressures and higher temperature combinations (throttle and reheat) than General Electric used, produced the higher efficiencies. Differences between the two contractors on capital cost estimates were the reason for the difference in absolute level of COE. The G.E. capital cost estimates were consistently higher for cases using similar parametric characteristics. A detailed comparison of conventional technology (base-line) steam plant capital costs is presented in reference 3. The difference between contractors was primarily in the balance-of-plant (BOP) materials costs estimated by the participating architect-engineering firms. Independent cost estimates, obtained by NASA according to ECAS ground rules, indicated steam plant capital costs lying between the G.E. and Westinghouse ECAS estimates.

Absolute cost differences notwithstanding, certain significant trends were shown in the results from both contractors: (1) the fluidized-bed furnaces (AFB and PFB) produced lower or comparable COE as measured against the conventional furnace with scrubber; and (2) lowest COE's were generally obtained at or near present state-of-the-art steam pressure and temperature conditions. The fuel cost savings (efficiency) from 1200^o F-and-higher steam conditions were clearly overshadowed by rapid increases in turbine capital cost.

OPEN-CYCLE GAS TURBINE

Both contractors studied simple-cycle and recuperated gas turbines and gas turbines with organic bottoming cycles. The influences of major parameters such as turbine inlet temperature, pressure ratio, turbine cooling method, uncooled ceramic materials, recuperator effectiveness, recuperator pressure drop, and organic working fluid were evaluated. General Electric emphasized the use of high-Btu gas, and Westinghouse emphasized a coal-

derived distillate as clean turbine fuels. A fuel conversion efficiency of 50 percent was selected by G.E. and Westinghouse for their fuels of emphasis, and fuel costs specified by NASA were identical. So even though the fuels emphasized were different, the overall results can be directly compared. For these fuels, powerplant efficiency would be twice the overall energy efficiency.

As shown in table X, the COE determined by G.E. ranged from 31 to 39 mills/kW-hr, and overall efficiency (including fuel-processing efficiency) ranged from 15 to 22 percent. Minimum COE (efficiency, 17 percent) occurred for the recuperated cycle with an effectiveness of 0.85 and a turbine inlet temperature of 2200⁰ F. Maximum efficiency occurred for a system with an organic bottoming cycle (COE, 34 mills/kW-hr) and a turbine inlet temperature of 2200⁰ F (highest temperature considered). An interesting single point presented by G.E. (but not included in table X) was for a recuperated cycle using solvent-refined coal (SRC) fuel (fuel conversion efficiency, 78 percent) for which the COE was 26 mills/kW-hr and the overall energy efficiency was 28 percent. The nitrogen oxides emission standard was not met for this case because of the fuel-bound nitrogen. However, this case indicates the desirable impact on COE and overall efficiency of the ability to use lower cost, semiclean fuels.

As also shown in table X, the COE determined by Westinghouse ranged from 28 to 42 mills/kW-hr, and the overall efficiency (including fuel-processing efficiency) ranged from 12 to 24 percent. Minimum COE (efficiency, 19 percent) occurred for the recuperated cycle with an effectiveness of 0.90 and a somewhat higher turbine inlet temperature than G.E.'s. Maximum efficiency (COE, 35 mills/kW-hr) occurred for a system with an organic bottoming cycle. The results also indicate that the use of ceramic blades and vanes would reduce COE somewhat more than 1 mill/kw-hr and would increase overall efficiency approximately 2 percentage points.

Comparing the G.E. and Westinghouse results for similar systems and operating parameters shows that G.E.'s COE is approximately 3 mills/kW-hr higher than Westinghouse's and that G.E.'s overall efficiency is approximately 2 percentage points lower than Westinghouse's. Performance calculations made at NASA show the difference in efficiency results to be totally accounted for by the difference in higher heating value of the fuels, the difference in the contractors' definitions of turbine inlet temperature (G.E. uses the temperature at the inlet to the first-stage rotor; Westinghouse uses the temperature at the inlet to the first-stage stator), the difference in recuperator performance, and G.E.'s use of the water injection to suppress nitrogen oxides. The cost difference was examined in detail but was not resolved. However, the costing approach and methodology used by G.E./Bechtel generally result in higher costs than Westinghouse's approach. Estimated capital costs are \$150/kWe for simple-cycle plants, \$200/kWe for recuperated systems, and of the order of \$400/kWe for bottomed systems. The increase in cost for organic bottoming is associated primarily with BOP costs. Both contractors' results agree on the major trends in the data. The cost of electricity decreases with increasing turbine

inlet temperature, to 2600⁰ F with air cooling and to 3000⁰ F with water cooling. Efficiency increases with increasing turbine inlet temperature, to 2600⁰ F with air cooling. Recuperation reduces COE and increases efficiency for the same operating conditions. Organic bottoming substantially increases efficiency but COE also increases. Although both contractors show increased COE for the organic bottoming, the doubling of capital cost (\$/kWe) for organic bottoming as compared to open-cycle recuperated gas turbine systems requires further investigation. According to Westinghouse's results, intercooling would increase overall efficiency by 1.5 percentage points and reduce COE about 2 mills/kW-hr.

COMBINED-CYCLE GAS TURBINE/STEAM TURBINE

Both contractors considered systems using low-Btu fuel gas derived from an integrated gasifier and systems using liquid and high-Btu gas fuels derived from coal in off-site processes; G.E. also evaluated the use of intermediate-Btu fuel gas. General Electric emphasized the use of a low-Btu integrated gasifier and nonreheat steam systems; Westinghouse emphasized distillate fuel from coal and evaluated both reheat and nonreheat steam systems. General Electric evaluated both air and water cooling; Westinghouse evaluated air cooling. The influences of major gas turbine parameters such as turbine inlet temperature, compressor pressure ratio, and blade and vane materials were evaluated. Major steam-bottoming-cycle parameters evaluated included throttle pressure and temperature.

As shown in table X, the COE determined by G.E. ranged from 23 to 33 mills/kW-hr, and overall efficiency (including fuel-processing efficiency) ranged from 21 to 37 percent. The lower overall efficiencies occurred for high-Btu gas (fuel conversion efficiency, 50 percent); the higher overall efficiencies occurred for cases with integrated low-Btu gasifiers. The COE of 23 mills/kW-hr was for the low-Btu gas fuel, near 2600⁰ F turbine inlet temperature, and near 37 percent overall efficiency. Water cooling resulted in higher COE and lower efficiency than air cooling at corresponding turbine inlet temperatures but would allow consideration of higher turbine inlet temperatures and possibly less-processed fuels.

As shown in table X, the COE determined by Westinghouse ranged from 24 to 34 mills/kW-hr, and the overall efficiency (including fuel-processing efficiency) ranged from 20 to 42 percent. The lower overall efficiency occurred for distillate fuel (fuel conversion efficiency, 50 percent); the higher overall efficiency occurred for a low-Btu integrated gasifier. The COE of 24 mills/kW-hr was for the low-Btu gas fuel, 2200⁰ F turbine inlet temperature, and 42 percent overall efficiency. These were the lowest COE and highest efficiency reported by Westinghouse. From the other parametric variations, higher turbine inlet temperatures would lead to higher efficiencies and lower COE.

The contractors' COE's for the low-Btu-gasifier case are in close agreement. Power-plant capital costs are within 10 percent and COE's within 5 percent. However, there is a

substantial difference of 7 percentage points in overall efficiency. The difference in overall performance is accounted for by the difference in performance of the gasifier and the steam bottoming cycle and the approach to gas cleanup. General Electric selected a fixed-bed gasifier requiring 1.1 pounds of steam per pound of coal, imposing a significant efficiency penalty on the G.E. steam bottoming cycle. Westinghouse selected an advanced fluidized-bed gasifier requiring 0.45 pound of steam per pound of coal. Westinghouse also used induction in the steam bottoming cycle to further improve efficiency. General Electric used cold-gas cleanup for the turbine, resulting in an additional efficiency penalty; Westinghouse used hot-gas cleanup. This comparison is better established by the Phase 2 results (section 5.2).

The following trends were indicated by the results:

- (1) Using low-Btu gas produced in powerplant-integrated gasifiers results in the highest overall energy efficiency and lowest COE for combined-cycle systems.
- (2) The cost of electricity decreases with increasing turbine inlet temperatures, to 2600° F with air cooling and to 3000° F with water cooling.
- (3) The powerplant efficiency of water-cooled turbines is lower than that of air-cooled turbines operating at the same gas temperatures; but, of course, metal temperatures are lower.
- (4) Reheat steam bottoming cycles are not attractive unless high turbine inlet temperatures are used.
- (5) Ceramic blades and vanes would be attractive at all firing temperatures considered.
- (6) Semiclean (minimally processed) liquid fuels provide attractive COE, efficiency, and capital cost for combined-cycle systems.

CLOSED-CYCLE GAS TURBINE

The closed-cycle gas-turbine system is one of those wherein the contractors' areas of emphasis differed considerably. The main differences involved the furnace and fuel types and integration of bottoming cycles.

General Electric emphasized atmospheric fluidized beds using direct coal firing. Of a total of 46 parametric cases, 35 used an atmospheric-fluidized-bed coal-fired furnace, one used a pressurized-fluidized-bed coal-fired furnace, and 10 used a clean-fuel pressurized furnace.

Westinghouse emphasized pressurized combustion loops and clean over-the-fence fuels. Of a total of 100 parametric cases, 88 used a pressurized furnace and clean fuel (distillate in 84 cases). Westinghouse studied 11 cases with pressurized-fluidized-bed furnaces with direct coal firing. They also did one case with an atmospheric furnace that used distillate fuel.

Both contractors used helium as the working fluid and varied such helium-loop param-

eters as pressure ratio, turbine inlet temperature, recuperator effectiveness, and pressure loss. Many of Westinghouse's parametric variations involved changes in the furnace-pressurizing gas-turbine parameters (which they referred to as the "pumpup cycle"). These included turbine inlet temperature, pressure ratio, recuperator effectiveness, and pressure loss. General Electric did few parametric variations of these furnace-pressurizing gas-turbine parameters but focused their attention on the helium cycle.

General Electric considered eight cases with an organic bottoming cycle (using R-22 and Fluorinol-85). A recuperated helium cycle was used in all cases. They also did five cases with a steam bottoming cycle and in all but one case used a recuperator in the helium cycle.

Westinghouse considered 45 parametric cases with a steam bottoming cycle, six with an organic cycle (R-12 and methylamine), and one with a sulfur dioxide bottoming cycle. In contrast to G.E., they configured the system so that the bottoming cycle received heat from the furnace cycle as well as from the helium cycle. Also in contrast to G.E., none of their bottomed cases included a recuperator in the helium cycle. As a result, the temperature levels of their bottoming cycles were generally higher than G.E.'s.

General Electric's recuperated closed-cycle gas turbine with AFB furnace had overall energy efficiencies from 26 to 33 percent and COE from 34 to 48 mills/kW-hr. The most attractive case had one stage of intercooling, 1500° F turbine inlet temperature, and 0.85 recuperator effectiveness. This case had about 32 percent overall efficiency and 34-mill/kW-hr COE. Their steam- and organic-bottomed cases yielded similar ranges in COE (but higher than that of unbottomed cases primarily because of higher balance-of-plant costs). The organic-bottomed cases resulted in higher efficiency. The highest efficiency was 38 percent with a COE of 42 mills/kW-hr.

The Westinghouse results with the highest overall energy efficiency and lowest COE were those with a PFB furnace or integrated gasifier. With a steam bottoming cycle, the PFB furnace cases reached 38 percent overall efficiency with a COE of 31 mills/kW-hr. Those cases with a recuperator and no bottoming cycle had from 31- to 38-mill/kW-hr COE and from 30 to 35 percent overall efficiency.

The Westinghouse cases using clean fuels and pressurized furnaces had lower overall energy efficiencies because of the fuel conversion efficiency. In terms of powerplant efficiency, however, the 1500° F inlet cases reached 43 percent with a bottoming cycle and 36 percent without. In spite of this and the lower capital cost, however, COE was higher than for the coal-fired cases because of the higher cost of distillate fuel.

Both contractors' results show that the use of intercooling in the recuperated, unbottomed cycle both increases overall efficiency and decreases COE. Both contractors' results also show that using bottoming cycles increases efficiency. However, caution must be exercised in comparing their results because of the different way they integrated the systems. Because of the way Westinghouse configured the system, most of the power comes from the bottoming and fur-

nance loops (less than 50 percent from the helium cycle). In G.E.'s case, most of the power comes from the helium cycle (approx. 80 percent).

Both contractors' results show that powerplant efficiency increases with increasing turbine inlet temperature, above 1500⁰ F. However, both used a clean-fueled furnace with high-temperature metallic heat exchangers. As a result the overall energy efficiency was lower than for the 1500⁰ F coal-fired cases, and the COE was substantially higher. In Phase 2 a nominally 1900⁰ F helium cycle using a coal-fired AFB furnace with a ceramic heat exchanger was studied.

SUPERCRITICAL CARBON DIOXIDE CYCLE

The supercritical carbon dioxide cycle was investigated only by G.E. (with Actron Industries as subcontractor) in the ECAS study. A total of 32 cases were examined, including variations in the fuel, furnace type, and primary-cycle configuration and operating parameters. Emphasis was on the atmospheric-fluidized-bed furnace, with variations to include one case with a pressurized fluidized bed and four cases with a pressurized furnace - three burning low-Btu gas from an integrated gasifier, and the fourth burning a high-Btu gas. The primary-cycle configurations considered were the simple (Feher), recompression, and post-heat cycles. The recompression cycle with a pump flow fraction of about 0.7 (ratio of pump flow to total flow) proved to be the most attractive of the three configurations in terms of cost of electricity and overall energy efficiency.

The supercritical carbon dioxide cycle was characterized by fairly good efficiencies but high cost of electricity (between 35 and 41 percent with corresponding COE's of 56 and 78 mills/kW-hr). The two best AFB cases in both efficiency and COE had overall energy efficiencies of 39 and 41 percent and COE's of 66 and 68 mills/kW-hr, respectively. The PFB case resulted in lower COE (about 57 mills/kW-hr) and about the same efficiency (somewhat over 39 percent) as the majority of the AFB cases. The PF cases with integrated low-Btu gasifiers offered the lowest COE (about 50 mills/kW-hr) but at a reduced efficiency (about 35 percent) because of the losses in the gasification process. An examination of the trends in the contractors' results showed that a modified cycle combining favorable variations in furnace type and cycle parameters might have a COE of about 55 mills/kW-hr at an overall energy efficiency of 40 percent.

The high COE of the supercritical carbon dioxide cycle is a result of very high component capital costs, primarily for the recuperator and turbine. For good efficiency, the cycle requires a very large recuperator that must accommodate differential pressures resulting from about 3800 psi on one side of the heat exchanger and 1400 psi on the other. The turbine must operate in an environment of both high pressure (3800 psi) and relatively high temperature (1350⁰ F). Innovative design approaches to these components are needed in order to arrive at less costly solutions to the design problems associated with the high pressures at relatively high temperatures that are peculiar to the supercritical carbon dioxide cycle. The scope

of Phase 1, however, did not provide an opportunity for detailed design studies. Phase 1 did identify the technical areas of focus if additional studies of this system are to be conducted. Because the costs of the recuperator and turbomachinery are such a large proportion of the total powerplant capital costs (over 50 percent for the base case studied by G.E.), the effect of possible reductions in the costs of these components that might result from detailed design studies was evaluated in a cursory manner. Reduced costs equal to approximately one-third of the original cost estimates were assumed for these components, based on equipment costs of other closed-cycle dynamic systems examined in the study. Applying these reduced costs to the modified cycle previously mentioned resulted in a COE of about 38 mills/kW-hr and an overall energy efficiency of about 40 percent, which is still not among the most attractive results of Phase 1.

LIQUID-METAL-RANKINE TOPPING CYCLE

This system consists of a Rankine topping cycle, with either potassium or cesium as the working fluid, rejecting heat to a conventional steam plant as a bottoming cycle. General Electric studied a total of 16 cases and Westinghouse a total of 50. Three types of furnace-boilers were examined, including the atmospheric fluidized bed, the pressurized furnace, and the pressurized fluidized bed. The fuel for the PF was either a low-Btu gas produced in a coal gasifier integrated with the power system or a high-Btu gas or liquid produced off site. General Electric emphasized the use of an AFB in their study; Westinghouse emphasized the PFB.

The best AFB case with potassium as a working fluid that was studied by G.E. had an overall energy efficiency of about 40 percent and a COE of about 48 mills/kW-hr. This represents both the highest efficiency and lowest COE of the AFB cases. The pressurized-furnace cases with integrated low-Btu gasifiers had somewhat lower efficiencies (approx. 35 percent) and lower COE's (approx. 40 to 41 mills/kW-hr). The single PFB case studied by G.E. had an overall energy efficiency of about 40 percent with a COE of about 40 mills/kW-hr. The Westinghouse results generally indicated higher efficiencies and lower COE's than G.E.'s results. The best case studied by Westinghouse, for both efficiency and COE, was a PFB case with an overall energy efficiency of about 44 percent and a COE of about 29 mills/kW-hr.

There are several reasons for the lower efficiencies of the G.E. cases, one of which contributes in varying degrees to all the configurations studied by G.E. A high potassium-recirculation ratio was assumed in the G.E. furnace/boiler designs on the basis of ensuring complete wetting of the horizontal tube walls. This resulted in high recirculating-pump power and efficiency penalties of about 2 percentage points for the AFB cases, about 1.5 percentage points for the PFB case, and about 0.3 percentage point for the PF with integrated low-Btu gasifier. Westinghouse, on the other hand, assumed vertical tubes and a recircula-

tion ratio of 2.5, with correspondingly low pump power and negligible effect on efficiency. Although the extent of recirculation that might be required is unknown at the present time, it is likely that recirculation ratios can be considerably lower than those used in the G.E. study because of the extreme ease with which potassium wets metal surfaces. Recirculation pumping power could then be reduced to the point where it has a very minor impact on the overall system efficiency. Also, in the PFB cases, the G.E. method of recovering exhaust heat from the pressurizing gas turbine through recuperation to the combustion air resulted in higher stack losses and lower efficiencies than were obtained in the Westinghouse cases. The configuration studied by Westinghouse included the recovery of the pressurizing-gas-turbine exhaust heat by the feedwater of the steam bottoming cycle.

The lower COE's of the Westinghouse results are attributable (1) to lower capital costs of all components in terms of \$/kWe and reduced fuel costs due simply to the effect of higher powerplant efficiencies, (2) to lower furnace-boiler costs due in part to lower pump costs resulting from lower recirculation-pumping requirements, and (3) to lower contingency allowances.

Both contractors' parametric variations using a PFB furnace resulted in the highest efficiency and lowest COE. However, G.E. favored the AFB furnace, primarily because of possible hot corrosion and erosion of the gas turbine blades from particulates and contaminants in the gases from the PFB. Although cesium appeared to offer some advantage in turbomachinery cost and size and a small advantage in efficiency, its higher cost and less-advanced state of technology would result in a much more costly development program. As a result of the trends indicated in the Phase 1 results, a potassium/steam system with a PFB furnace was chosen for study in Phase 2.

OPEN-CYCLE MHD

Magnetohydrodynamic (MHD) power systems are of interest for advanced powerplants primarily because of their high-efficiency potential. This potential is the direct result of their high maximum operating temperatures. The MHD working fluid exiting the generator is also at a relatively high temperature, and this heat must be used in order to obtain high efficiency. This is accomplished by using the MHD generator exhaust to preheat the oxidizer (and sometimes the fuel) and to produce additional power in a bottoming plant. In addition to a large number of possible MHD operating parameters, there are many different configurations for such an MHD plant. These involve a variety of bottoming-cycle types and their integration with the MHD cycle, a variety of methods of preheating the oxidant, and a range of possible fuels and oxidants. A representative sample of such variations has been studied in ECAS.

General Electric studied 30 parametric cases, 23 of which used direct coal firing and

seven of which used solvent-refined coal (SRC) as the fuel. All but one case used a steam bottoming cycle; that one case used a gas turbine bottoming cycle. All but two cases used a high-temperature (2000°F and higher) regenerative heat exchanger to preheat the air with the MHD generator exhaust gas (i.e., direct air preheat). One used lower temperature (1500°F) direct air preheat with oxygen enrichment, and the other assumed the air to be preheated by a separate clean fuel gas from a coal gasifier (i.e., indirect air preheat).

Westinghouse studied 39 parametric cases, 34 of which were directly coal fired and five of which used a low-Btu fuel gas obtained from an integrated gasifier. Half of their direct-coal-fired cases used direct air preheat to about 2400°F ; and the others assumed direct air preheat to as high as 2400°F , followed by additional heating in an indirect air preheater. The fuel for the indirect air preheater was the volatiles obtained by carbonizing the coal before using it in the main combustor. All the Westinghouse cases used a steam bottoming cycle.

The G.E. coal-fired cases ranged from 44 to 53 percent in overall efficiency, and their SRC cases ranged from 40 to 46 percent. The SRC fuel cases suffer from the assumed 78 percent fuel conversion efficiency; their powerplant efficiency, not including this fuel conversion penalty, ranged from 52 to 59 percent. The costs of electricity ranged from 41 to 48 mills/kW-hr.

The Westinghouse coal-fired, direct-air-preheat cases ranged from 44 to 49 percent in efficiency and 27 to 31 mills/kW-hr in COE. The coal-fired cases with direct and indirect air preheat ranged from 44 to 54 percent in efficiency and 27 to 35 mills/kW-hr in COE. The higher efficiency was obtained by air preheat to about 3500°F . With indirect air preheat to about 3000°F , 50 percent efficiency was obtained. The cases using low-Btu fuel gas ranged from 46 to 54 percent in efficiency and 34 to 42 mills/kW-hr in COE.

For nearly comparable conditions, both G.E. and Westinghouse obtained efficiencies of about 49 percent. This is for a direct-coal-fired powerplant using direct air preheat to 2400° to 2500°F and a $3500\text{-psi}/1000^{\circ}\text{F}/1000^{\circ}\text{F}$ steam bottoming cycle. The cost estimates, however, are substantially different. The G.E. COE for these conditions is 44 mills/kW-hr, and the Westinghouse COE is 27 mills/kW-hr. Most of this difference is due to a difference in powerplant capital cost estimates. The G.E. and Westinghouse results were $\$1102/\text{kWe}$ and $\$642/\text{kWe}$, respectively. The Westinghouse cost estimates for several of the major components were higher than G.E.'s estimates. General Electric's estimates for balance-of-plant materials and installation costs, however, were higher than Westinghouse's estimates. Differences in the estimates of major-component costs can be resolved only after further technological development and more-detailed study. The parameters chosen for the Phase 2 conceptual design are similar to these two cases. The Phase 2 results show lower cost estimates for BOP items than the G.E. Phase 1 estimates (section 5.2.5).

CLOSED-CYCLE INERT-GAS MHD

The contractors differed in both the powerplant configurations considered for the closed-cycle, inert-gas MHD system and in their approach to evaluating the system's performance. General Electric studied configurations with MHD cycles bottomed by steam cycles and configurations with recuperative MHD cycles in parallel with a steam cycle. The fuel energy is transferred from a nominally atmospheric combustion loop to the MHD working gas by a refractory regenerative heat exchanger. In the parallel-cycle concept, a fraction of the combustion energy is transferred to a recuperative MHD Brayton cycle through the refractory regenerative heat exchanger, and the remaining combustion energy is transferred directly to the steam boiler of the parallel steam cycle. Initially, all the MHD topping-cycle configurations used an over-the-fence processed fuel, and the parallel-cycle configurations were directly coal fired. The majority of the over-the-fence fuel cases used solvent-refined coal with a conversion efficiency of 78 percent. As the study progressed, G.E. added two direct-coal-fired MHD topping cycles. The MHD-topped steam cycle was the only configuration considered by Westinghouse. The fuel used in the majority of cases was a low-Btu gas derived from an on-site gasifier. Westinghouse evaluated the system performance by doing efficiency calculations for a wide range of generator parameters and then optimizing the thermodynamic efficiency for a given generator inlet temperature. The costs were then calculated for these optimum efficiency points.

Besides the different powerplant configurations considered, variations in coal type, generator inlet temperature (2400° to 3800° F), generator inlet pressure (10 to 20 atm), generator turbine effectiveness (0.6 to 0.8), and power level were also studied.

The G.E. results for the parallel cycle and the processed over-the-fence fuel MHD topping cycle indicate that these are not attractive systems. The overall energy efficiencies for the parallel cycle ranged from 35 to 39 percent, the capital costs varied from \$1654/kWe to \$1886/kWe, and the COE from 66 to 73 mills/kW-hr. The powerplant efficiencies for the processed-fuel MHD topping cycles are much higher (35 to 46 percent), but the overall energy efficiencies are from 26 to 36 percent when the fuel conversion efficiency is considered. The capital costs and COE range from \$1300/kWe to \$1535/kWe and from 58 to 66 mills/kW-hr, respectively, for this configuration. The COE's for these systems are 2 to 2.5 times that of the G.E. advanced steam case.

The best G.E. results were obtained for the direct-coal-fired MHD topping systems. Two of these cases were considered. The first case, with an inlet temperature of 3000° F, an MHD-generator adiabatic efficiency of 0.7, and a magnetic field strength of 3.5 teslas, resulted in an overall energy efficiency of 42 percent, a capital cost of \$1551/kWe, and a COE of 62 mills/kW-hr. A single iteration was made on this configuration, in which the temperature is 3121° F, the MHD-generator adiabatic efficiency is 78 percent, and the magnetic field is

4.5 teslas; and additional effort was expended on the powerplant layout. This case had an overall efficiency of 46 percent, a capital cost of \$1109/kWe, and a COE of 46 mills/kW-hr.

The Westinghouse overall energy efficiencies for the low-Btu-gasifier configuration were 46 percent at an inlet temperature of 3800° F and 42 percent at 3100° F. This includes an effective efficiency of the gasifier/combustion loop combination of about 78 percent. The capital costs and COE at 3800° F range from \$2228/kWe to \$2434/kWe and from 77 to 85 mills/kW-hr. At 3100° F, the capital costs were \$1912/kWe and the COE was 68 mills/kW-hr.

There are no irreconcilable differences between the G.E. and Westinghouse efficiencies when the different assumptions, operating conditions, and combustion-loop efficiencies are considered. However, the Westinghouse capital costs for a nearly equivalent system were approximately \$400/kWe higher than G.E.'s. This difference is mainly due to the differences in the costs of the refractory regenerative heat-exchanger system. As part of the NASA ECAS-supporting studies, Fluidyne Engineering Corp., through a contract with Burns and Roe, Inc., estimated the costs of similar heat exchangers. These estimates were much closer to G.E.'s than Westinghouse's cost estimates. If the lower heat-exchanger estimates were used, the Westinghouse COE results would be lowered to about 44 mills/kW-hr.

The best configuration considered was the direct-coal-fired MHD topping cycle with an efficiency of 46 percent and a COE of 46 mills/kW-hr. Pressurization of the combustion loop might further reduce the costs of this system. The low-Btu-gasifier cases considered have lower efficiencies and generally higher costs than the direct-coal-fired systems at equivalent generator inlet temperatures. More closely integrating the gasifier and optimizing the economics might significantly improve the initial results obtained for this configuration.

LIQUID-METAL MHD

General Electric (and their subcontractor, Argonne National Laboratory) and Westinghouse approached the liquid-metal MHD systems in a similar manner. Both used the two-phase liquid-metal MHD power cycle with an inert gas as the primary thermodynamic working fluid and a liquid metal as the electrodynamic fluid in the MHD generator. At the lower temperatures considered (1200° to 1300° F), G.E. used a helium/sodium working fluid and Westinghouse used argon/sodium. Westinghouse considered the use of both argon/sodium and helium/lithium at the higher temperatures (1400° to 1500° F), but G.E. used only helium/lithium. The majority of cases studied by both contractors included a binary liquid-metal MHD/steam cycle, a steam cycle with little regenerative feedwater heating, and pumps to recirculate the liquid metal. Cases were included, however, to determine the effect of eliminating the liquid-metal pumps.

Both contractors used modularized MHD generators that are operated hydraulically in parallel and electrically in series. The series connection is required to attain a reasonable

voltage level for the inverters.

The contractors' approach to the parametric variations differed somewhat. The majority of the Westinghouse cases used a cyclone combustor, Illinois #6 coal, a power level of approximately 1000 MWe, and various liquid-metal-system parameters. The G.E. cases mainly treated variations in combustors, fuels, and power level.

The overall energy efficiencies obtained by both contractors were quite similar. At temperatures of 1200° to 1300° F, they ranged from 34 to 37 percent, and at 1400° to 1500° F from 37 to 40 percent. The costs were significantly different, however. For the lower temperature cases, the G.E. costs were \$1450/kWe to \$2570/kWe and 77 to 93 mills/kW-hr, and Westinghouse's were \$790/kWe to \$1177/kWe and 34 to 46 mills/kW-hr. At 1400° to 1500° F the ranges were as follows: G.E., \$2500/kWe to \$3000/kWe and 92 to 100 mills/kW-hr; Westinghouse, \$1165/kWe to \$2140/kWe and 45 to 78 mills/kW-hr.

Differences exist between the cost estimates made by the two contractors for almost every major item in these systems. Differences in the costs of such major components as the magnet, MHD generator, and power-conditioning equipment have been reconciled by consideration of the different design philosophies used by the contractors. Westinghouse attempted to minimize the MHD generator, magnet, and liquid-metal piping costs in their design approach. Inverter costs differ (G.E., \$200/kWe; Westinghouse, \$39/kWe) because G.E. required direct-current interrupters in their system and Westinghouse did not. However, for equivalent powerplants, there are still unresolved cost differences of approximately \$300 million between the contractors' results.

The highest overall energy efficiency obtained by the contractors at the temperature limits dictated by the present sodium technology (1200° to 1300° F) was 37 percent. Their results indicate that the maximum potential efficiency at these temperatures would be approximately 40 percent. This is based on assuming a generator isentropic efficiency of 0.80, the development of a highly efficient nozzle/separator/diffuser, and optimistic system component efficiencies. The overall energy efficiency is limited to about 40 percent because at these temperatures the liquid-metal MHD system cannot be effectively coupled to an advanced steam plant. Because of a pinch-point problem in the steam boiler, both contractors found that the highest liquid-metal MHD/steam system efficiencies were obtained by using a steam plant with minimal regenerative feedwater heating and with the steam reheat energy being supplied by the combustor. The adverse effect of this coupling is twofold. The thermodynamic efficiency of the steam bottoming plant is limited to approximately 39 percent, and the system does not derive the full benefit of the topping cycle because a portion of the combustion energy is transferred directly to the steam plant.

At the higher temperature considered in this study (1500° F), these problems may be alleviated. Westinghouse has calculated an overall energy efficiency of 43 percent by assuming that the sodium technology can be extended to 1500° F and that the system can be coupled

to a 45-percent-efficient steam plant. Sodium vapor carryover could be a considerable problem at these temperatures. However, only a few of the higher temperature systems were considered by the contractors in this study, and the potential for improvement from better coupling with an advanced steam plant at higher temperature is indicated. Resolution of the large differences in cost estimates requires more-detailed component design and plant-integration optimization.

FUEL CELLS

In ECAS Phase 1, three types of low-temperature fuel cells and two types of high-temperature fuel cells were studied. Both contractors studied the low-temperature (375°F) phosphoric acid fuel cell system and the high-temperature (approx. 1832°F) zirconia solid-electrolyte (SE) fuel cell system. Other low-temperature fuel cells studied were the solid-polymer-electrolyte (SPE) system by G.E. and an aqueous alkaline (KOH) fuel cell system by Westinghouse. Also included in the Westinghouse study was the high-temperature (approx. 1200°F) molten-carbonate fuel cell. The G.E. study included 19 parametric cases, with primary emphasis given to low-temperature fuel cells; the Westinghouse study included 69 parametric cases approximately evenly distributed between the low- and high-temperature fuel-cell systems. In this parametric study the influences of powerplant size, fuel type, oxidant type, temperature, electrolyte thickness, catalyst loading, and fuel cell life were evaluated.

High-Temperature Fuel Cells

The principal reasons for the high efficiency of high-temperature-fuel-cell systems are as follows: (1) the increase in reaction rates (reduced polarization) brought about by high temperature, which helps the fuel cell to approach its theoretical potential for high efficiency; and (2) utilization of high-quality fuel cell waste heat by the gasifier and/or bottoming cycle. The Westinghouse cases that are integrated with a gasifier and/or steam bottoming cycle so as to recovery fuel cell waste heat were compared with those cases that include neither a gasifier nor a bottoming cycle. The overall efficiency gain due to fuel cell waste-heat utilization was approximately 15 percentage points.

For the Westinghouse zirconia SE fuel cell the efficiencies of the integrated cases were between 48 and 53 percent. (The 53 percent efficiency was reported for the well-known Westinghouse "Project Fuel Cell" concept, in which the fuel cells are actually housed inside the gasifier in order to maximize heat and mass transfer to the gasifier.) The overall efficiency for the molten-carbonate fuel cell using a steam bottoming cycle was 46 percent. The SE fuel cell concepts of G.E. and Westinghouse are different. The more conservative G.E. approach involves thicker solid electrolytes than does the Westinghouse approach. This results in

higher resistances (lower voltages) and consequently lower efficiencies.

An uncertain factor that, as expected, has a significant influence on COE is the useful life of the fuel cell. For assumed 10 000-hour lives, Westinghouse estimated costs for a zirconia SE and a molten-carbonate fuel cell (each with a steam bottoming cycle) to be 40 and 44 mills/kW-hr, respectively. On the other hand, for 50 000-hour lives the costs would be close to 30 mills/kW-hr for each high-temperature system. The G.E. zirconia cost estimates of 42 to 45 mills/kW-hr are consistent with the Westinghouse cost estimates. The G.E. estimate is based on very long life (about 100 000 hr), but the lower efficiency of the G.E. concept raises the overall COE to more than that of the 50 000-hour Westinghouse case.

Low-Temperature Fuel Cells

Low-temperature fuel cells are less suited for the primary ECAS utility application, that is, baseload power generation from coal-derived fuels. First of all, the requirements for clean fuel are much more stringent for low-temperature fuel cells than for high-temperature fuel cells. Secondly, there is less potential for utilization of waste heat in the powerplant at the low temperatures. Third, the rate processes are slower at low temperature, and polarization losses are significant at current density levels that result in optimum power. All three conditions reduce the efficiency of a low-temperature-fuel-cell powerplant. However, greater utilities' applications for low-temperature fuel cells are foreseen, outside the context of ECAS, for nonbaseload service. The potential for near-term utilities application of fuel cell systems may be dispersed power generators in peaking or intermediate service.

In both G.E. and Westinghouse studies the highest overall efficiencies (31 percent) for low-temperature-fuel-cell powerplants reach only the lower end of the overall efficiencies of the high-temperature system (table X).

Both contractors considered a phosphoric acid case very similar to the 27-MWe fuel cell powerplant being developed for commercial service (United Technologies Corp. FCG-1). The G.E. estimate of COE for this case was 52 mills/kW-hr and that of Westinghouse was 40 mills/kW-hr (both based on 40 000-hr life). General Electric's higher COE is attributable primarily to a much higher fuel-processing cost (\$173/kWe) than that estimated by Westinghouse (\$38/kWe). The G.E. fuel-processing cost estimate appears high, and the Westinghouse estimate appears somewhat low. The powerplant efficiencies estimated by G.E. and Westinghouse for these cases were 30 and 36 percent, respectively. The difference reflects the contractors' estimates of fuel cell efficiency and the degree of integration of the fuel cell with the fuel processor. Finally, the overall efficiency estimates for these cases were 24 and 15 percent for Westinghouse and G.E., respectively. These reflect the large efficiency penalty to be paid in producing high-Btu gas in a gasifier (50 and 67 percent off-site fuel conversion efficiencies assumed by G.E. and Westinghouse, respectively).

An interesting case in the study of the SPE fuel cell is an SPE system operating on over-the-fence hydrogen/oxygen and producing 201 MWe. Hydrogen/oxygen is the most desirable fuel/oxidant combination for maximizing powerplant efficiency. Cost of electricity was reduced because the supply of hydrogen eliminates the need for a fuel processor. This G.E. SPE low-temperature-fuel-cell case had an overall efficiency of 31 percent and a COE of 31 mills/kW-hr. However, if the energy required to produce oxygen is calculated (to take into account the oxygen-plant power drain on the fuel cell), it would reduce overall efficiency to an estimated 26.5 percent and increase COE to approximately 37 mills/kW-hr. In addition, the basic COE probably reflects an optimistic projection of cell costs and polymer life at 300° F.

The costs for the aqueous alkaline fuel cell systems studied by Westinghouse were higher than those of similar phosphoric acid fuel cell systems. The reasons for the higher costs are (1) additional reactant processing is required to guard against carbonation of the alkaline electrolyte, and (2) lower power densities are obtained with the alkaline fuel cell at 158° F than with the phosphoric acid fuel cell at 375° F. The COE for 10 000- to 30 000-hour alkaline systems is in the 50- to 61-mill/kW-hr range.

APPENDIX B

STEAM SYSTEM WITH STACK-GAS SCRUBBERS

A steam powerplant with a conventional pulverized-coal-burning furnace and wet-lime stack-gas scrubbers was studied by G.E. and funded by the Tennessee Valley Authority (TVA) and the Environmental Protection Agency (EPA). These results are reported in reference 9. The study followed the same ground rules and procedures used in analyzing the Phase 2 ECAS systems discussed in section 5.0. The throttle and reheat conditions were 3500 psig/1000° F/1000° F, the same as for the advanced steam system with fluidized-bed boilers discussed in section 5.2.1. The steam cycle included seven regenerative feedwater heaters to yield a final feedwater temperature of 505° F at 100 percent operating load. The use of wet-lime scrubbers with on-site calcination of limestone was specified to G.E. The TVA then estimated changes in the system cost for variations in the scrubbing process.

The simplified schematic of the system is shown in figure 25; the steam cycle and coal-fired furnace are conventional. The combustion gases at the exit from the furnace are used for air preheating and are reduced in temperature to 300° F before entering the electrostatic precipitators. In the scrubbers, the gas is cooled to 125° F by a lime-slurry spray and the sulfur is removed as calcium sulfite and calcium sulfate. The flue gas leaving the scrubbers at 125° F is saturated with water vapor and has corrosive constituents at or near their dew-points. To avoid condensation of these constituents and corrosion of the ducting and stack, the flue gases are reheated at the scrubber exit. This reheating is accomplished by using steam extracted from the turbine to heat ambient air to 334° F, which is then mixed with the flue gases to reach the desired stack inlet temperature. Use of heat exchangers for reheating this corrosive gas mixture is thus avoided.

Two stack temperatures were considered by G.E., 250° F and 175° F. The 250° temperature is typical conventional practice without stack-gas scrubbers. But because the steam extraction for flue-gas reheating significantly reduces system efficiency, this system is much more sensitive to stack temperature than a system without scrubbing. Also since the 125° F dewpoint of the flue gas is much lower than in a system without scrubbers, lower stack temperatures are of interest. The steam extraction for flue-gas reheating for the 175° F case is only about 23 percent of the amount required for the 250° F case.

The results are summarized in table XI. The steam-cycle thermodynamic efficiency shown is lower than the 43.9 percent for the AFB/steam system discussed in section 5.0 because steam is extracted for flue-gas reheating. This reduction in efficiency is much larger for the 250° F stack temperature because of the larger steam extraction. Because of the lower thermodynamic efficiency, the slightly higher auxiliary power requirements, and the use of a small amount of coal for limestone calcination, the system with a stack-gas

TABLE XI. - SUMMARY OF G.E. RESULTS FOR STEAM
SYSTEM WITH STACK-GAS SCRUBBERS USING LIME
WITH ON-SITE CALCINATION

Result	Stack temperature, °F	
	250	175
Net power output, MWe	747	795
Efficiency, percent:		
Thermodynamic	40.7	43.1
Overall	31.8	33.8
Capital cost, \$/kWe:		
Using ECAS ground rules	835	771
For constant mid-1975 dollars	591	545
Cost of electricity, mills/kW-hr:		
Using ECAS ground rules	39.8	37.0
For constant mid-1975 dollars	32.1	29.9
Construction period, yr	5.5	5.5
Emissions, lb/MBtu:		
Sulfur dioxide	0.867	0.867
Nitrogen oxides	0.65	0.65
Particulates	0.092	0.092
Limestone input, lb/kW-hr	0.16	0.15
Water input, gal/kW-hr	0.82	0.77
Sludge (solids) output, lb/kW-hr	0.19	0.18
Dry fly ash, lb/kW-hr	0.07	0.07
Land, acre/100 MWe:		
Powerplant	12.3	11.6
Waste disposal	^a 239 ^b 122	^a 225 ^b 115

^aBased on 1785 acres quoted by G.E.

^bBased on 0.19-lb/kW-hr sludge (solids) output,
40-percent pond solids concentration, 22-
foot pond depth, and 30-year operation
at 65 percent capacity factor.

scrubber has lower overall energy efficiency than the 35.8 percent obtained for the AFB/steam system.

The costs are given in table XI both according to the ECAS ground rules and in terms of constant mid-1975 dollars as was done in table 5.1-1 for the other ECAS Phase 2 systems and explained in section 5.1. The capital costs shown include the stack-gas scrubbers and all associated equipment and installation costs but do not include the land acquisition costs. The land preparation costs for one sludge-disposal pond with 5 years' capacity are included. The stack-gas-scrubber equipment was sized to be capable of 90-percent sulfur removal from 4.5-percent-sulfur coal in order to provide a margin above the requirements for the

3.9-percent-sulfur Illinois #6 coal specified for the study. The operating conditions calculated, however, assumed the use of 3.9-percent-sulfur coal.

The lower capital cost (in \$/kWe) of the 175° F stack temperature case in figure 25 is largely due to the higher power output that results from the need for less steam extraction for flue-gas reheating. There is also a slight reduction in cost (in terms of dollars) due to the smaller equipment needed in the 175° F-stack-temperature case for flue-gas reheating. The COE is lower both because of lower capital cost and higher efficiency.

The emissions and natural resource requirements for the two cases are the same in absolute terms; but when expressed in terms of kilowatt-hours of output, they are lower for the 175° F-stack-temperature case due to its higher efficiency.

The sludge ponds were assumed by G.E. to be on or immediately adjacent to the power-plant site. Supernatant water is pumped from the ponds and recirculated to the scrubbers. For a steady-state settled condition of 40-percent solids, the volume of wastes for 30 years of operation at 65 percent capacity factor would be about 20 000 acre-feet, based on the 0.19-lb/kW-hr sludge-solids output shown in table XI. Thus, 909 acres would be required for a 22-foot depth, or 122 acres per 100 MWe (table XI). As indicated in the table, G.E. allowed 239 acres per 100 MWe (1785 acres at a 22-ft depth) in their plant layout. But as in the case of all the ECAS systems discussed in section 5.0, they did not include the land acquisition

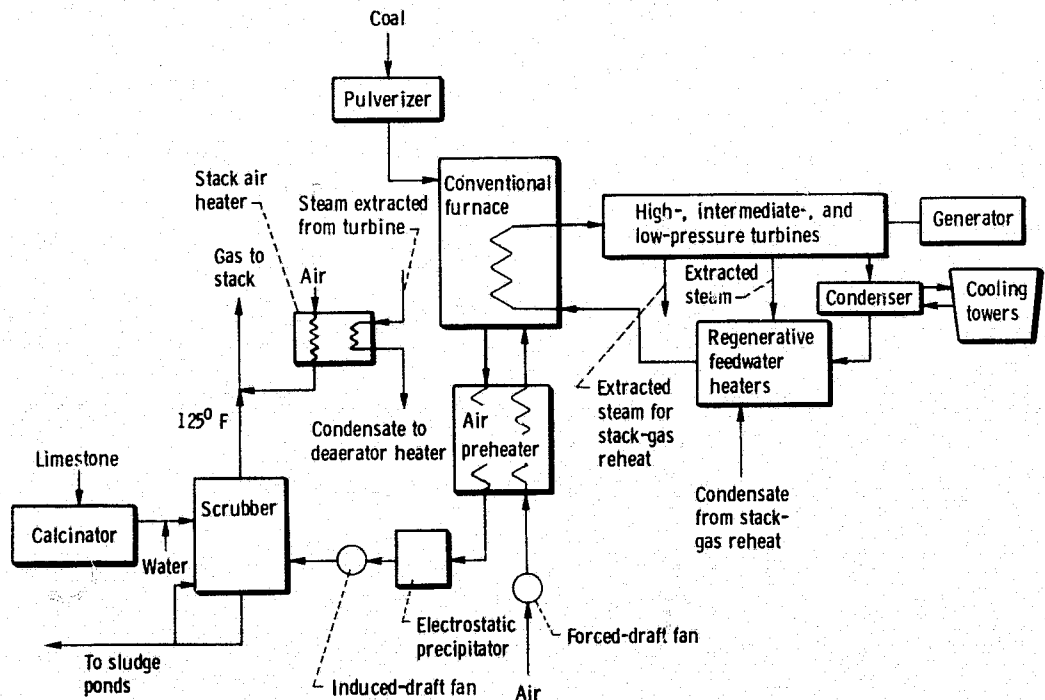


Figure 25. - Simplified schematic diagram of steam system with wet-limestone stack-gas scrubbers.

costs.

The modifications in cost estimates made by TVA are briefly summarized in table XII. These are based on the 175⁰ F-stack-temperature case considered by G.E. For the system with lime scrubbers and on-site calcination, TVA's modifications consisted basically of using four scrubber trains rather than the six used by G.E. and including the land costs. The change in scrubbers was made on the basis of different scrubber technology assumptions, which would allow about a 50 percent increase in gas velocity. As indicated by table XII, the cost variations resulting from TVA's analysis are less than 2 mills/kW-hr, less than the difference between the COE for this system and those of the ECAS systems listed in table V.

TABLE XII. - TVA MODIFICATIONS TO G. E. COST ESTIMATES,
175⁰ F STACK TEMPERATURE

	Capital cost, \$/kWe	Cost of electricity, mills/kW-hr
G. E. result with lime scrubbers and on-site calcination	771	37.0
TVA estimates:		
System with lime scrubbers and on-site calcination	782	38.6
System with lime scrubbers and purchased lime	759	38.0
System with limestone scrubbers	774	38.0
System with regenerable magnesia scrubbers	728	36.7

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APPENDIX C

GLOSSARY

A&E	architect-engineer
AFB	atmospheric fluidized bed
BOP	balance of plant
CCMHD	closed-cycle magnetohydrodynamic
CF	conventional furnace
CGT	closed-cycle gas turbine
COE	cost of electricity
ECAS	Energy Conversion Alternatives Study
EPA	Environmental Protection Agency
ERDA	Energy Research and Development Administration
FL-85	Fluorinol-85 working fluid
G.E.	General Electric Co.
HBTU	high-Btu gas
HHV	higher heating value
IBTU	intermediate-Btu gas
IGT	Institute of Gas Technology
LBTU	low-Btu gas
LMMHD	liquid-metal magnetohydrodynamic
LMR	liquid metal Rankine
MHD	magnetohydrodynamic
NASA	National Aeronautics and Space Administration
NSF	National Science Foundation
OCMHD	open-cycle MHD
OGT	open-cycle gas turbine
O&M	operation and maintenance
OMB	Office of Management and Budget

PF	pressurized furnace
PFB	pressurized fluidized bed
R-12	Freon working fluid
R-22	Freon working fluid
R&D	research and development
SE	solid electrolyte
SPE	solid polymer electrolyte
SRC	solvent-refined coal
TVA	Tennessee Valley Authority
UTC	United Technologies Corp.

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